Robert M. Fagan

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SUMMARY

Mechanical engineer and energy economics analyst with over 20 years experience in the energy industry. Activities focused primarily on electric power industry issues, especially economic and technical analysis of transmission pricing structures, wholesale electricity markets, renewable resource alternatives and assessment and implementation of demand-side alternatives.

In-depth understanding of the complexities of, and the interrelationships between, the technical and economic dimensions of the electric power industry in the US and Canada, including the following areas of expertise:

- Wholesale energy and capacity provision under market-based and regulated structures.
- Extent of competitiveness of existing and potential wholesale market structures.
- Transmission use pricing, encompassing congestion management, losses, LMP and alternatives, financial and physical transmission rights; and transmission asset pricing (embedded cost recovery tariffs).
- Physical transmission network characteristics; related generation dispatch/system operation functions; and technical and economic attributes of generation resources.
- RTO and ISO tariff and market rules structures and operation.
- FERC regulatory policies and initiatives, including those pertaining to RTO and ISO development and evolution.
- Demand-side management, including program implementation and evaluation; and load response presence in wholesale markets.
- Building energy end-use characteristics, and energy-efficient technology options.
- Fundamentals of electric distribution systems and substation layout and operation.
- Energy modeling (spreadsheet-based, GE MAPS and online DOE-2 residential).
- State and provincial level regulatory policies and practices, including retail service and standard offer pricing structures.
- Gas industry fundamentals including regulatory and market structures, and physical infrastructure.

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. 2004 – Present. Senior Associate
Responsibilities include consulting on issues of energy economics, analysis of electricity utility planning, operation, and regulation, including issues of transmission, generation, and demand-side management. Provide expert witness testimony on various wholesale and retail electricity industry issues. Specific project experience includes the following:

- Analysis of effect of increasing the system benefits charge (SBC) in Maine to increase procurement of energy efficiency and DSM resources; analysis of impact of DSM on transmission and distribution reinforcement need.
- Evaluation of wind energy potential and related transmission issues in Minnesota.
- Evaluation of wind energy "firming" premium in BC Hydro Energy Call in British Columbia.
- Evaluation of pollutant emission reduction plans and the introduction of an open access transmission tariff in Nova Scotia.
- Evaluation of the merger of Duke and Cinergy with respect to Indiana ratepayer impacts.
- Review of the termination of a Joint Generation Dispatch Agreement between sister companies of Cinergy.
- Assessment of the potential for an interstate transfer of a DSM resource between the desert southwest and California, and the transmission system impacts associated with the resource.
- Analysis of various transmission system and market power issues associated with the proposed Exelon-PSEG merger.
- Assessment of market power and transmission issues associated with the proposed use of an auction mechanism to supply standard offer power to ComEd native load customers.
- Review and analysis of the impacts of a proposed second 345 kV tie to New Brunswick from Maine on northern Maine customers.

Tabors Caramanis & Associates, Cambridge, MA 1996 -2004. Senior Associate.

- Provided expert witness testimony on transmission issues in Ontario and Alberta.
- Supported FERC-filed testimony of Dr. Tabors in numerous dockets, addressing various electric transmission and wholesale market issues.
- Analyzed transmission pricing and access policies, and electric industry restructuring proposals in US and Canadian jurisdictions including Ontario, Alberta, PJM, New York, New England, California, ERCOT, and the Midwest. Evaluated and offered alternatives for congestion management methods and wholesale electric market design.
- Attended RTO/ISO meetings, and monitored and reported on continuing developments in the New England and PJM electricity markets. Consulted on New England FTR auction and ARR allocation schemes.
- Evaluated all facets of Ontario and Alberta wholesale market development and evolution since 1997. Offered congestion management, transmission, cross-border interchange, and energy and capacity market design options. Directly participated in the Ontario Market Design Committee process. Served on the Ontario Wholesale Market Design technical panel.

- Member of TCA GE MAPS modeling team in LMP price forecasting projects.
- Assessed different aspects of the broad competitive market development themes presented in the US FERC's SMD NOPR and the application of FERC's Order 2000 on RTO development.
- Reviewed utility merger savings benchmarks, evaluated status of utility generation market power, and provided technical support underlying the analysis of competitive wholesale electricity markets in major US regions.
- Conducted life-cycle utility cost analyses for proposed new and renovated residential housing at US military bases. Compared life-cycle utility cost options for large educational and medical campuses.
- Evaluated innovative DSM competitive procurement program utilizing performance-based contracting.

Charles River Associates, Boston, MA, 1992-1996. **Associate**. Developed DSM competitive procurement RFPs and evaluation plans, and performed DSM process and impact evaluations. Conducted quantitative studies examining electric utility mergers; and examined generation capacity concentration and transmission interconnections throughout the US. Analyzed natural gas and petroleum industry economic issues; and provided regulatory testimony support to CRA staff in proceedings before the US FERC and various state utility regulatory commissions.

Rhode Islanders Saving Energy, Providence, RI, 1987-1992. **Senior Commercial/Industrial Energy Specialist**. Performed site visits, analyzed end-use energy consumption and calculated energy-efficiency improvement potential in approximately 1,000 commercial, industrial, and institutional buildings throughout Rhode Island, including assessment of lighting, HVAC, hot water, building shell, refrigeration and industrial process systems. Recommended and assisted in implementation of energy efficiency measures, and coordinated customer participation in utility DSM program efforts.

Fairchild Weston Systems, Inc., Syosset, NY 1985-1986. Facilities Engineer. Designed space renovations; managed capital improvement projects; and supervised contractors in implementation of facility upgrades.

Narragansett Electric Company, Providence RI, 1981-1984. Supervisor of Operations and Maintenance. Directed electricians in operation, maintenance, and repair of high-voltage transmission and distribution substation equipment.

EDUCATION

Boston University, M.A. Energy and Environmental Studies, 1992
Resource Economics, Ecological Economics, Econometric Modeling

Clarkson University, B.S. Mechanical Engineering, 1981
Thermal Sciences

Additional Professional Training and Academic Coursework

Utility Wind Integration Group - Short Course on Integration and Interconnection of Wind Power Plants Into Electric Power Systems (2006).
Regulatory and Legal Aspects of Electric Power Systems – Short Course – University of Texas at Austin (1998)
Illuminating Engineering Society courses in lighting design (1989).
Coursework in Solar Engineering; Building System Controls; and Cogeneration at Worcester Polytechnic Institute and Northeastern University (1984, 1988-89).
Graduate Coursework in Mechanical and Aerospace Engineering – Polytechnic Institute of New York (1985-1986)

SUMMARY OF TESTIMONY, PUBLICATIONS, AND PRESENTATIONS

TESTIMONY

State of Maine Public Utilities Commission. Pre-filed testimony on the ability of DSM and distributed generation potential to reduce local supply area reinforcement needs. Testimony filed before the Commission on a Request for Certificate of Public Convenience and Necessity to Build a 115 kV Transmission Line between Saco and Old Orchard Beach. Testimony filed jointly with Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2006-487, February 27, 2007.

Minnesota Public Utilities Commission. Rebuttal Testimony on wind energy potential and related transmission issues in the Certificate of Need proceeding for the Big Stone II coal-fired power plant proposal. In the Matter of the Application by Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota and In the Matter of the Application to the Minnesota Public Utilities Commission for a Route Permit for the Big Stone Transmission Project in Western Minnesota. OAH No. 12-2500-17037-2 and OAH No. 12-2500-17038-2; and MPUC Dkt. Nos. CN-05-619 and TR-05-1275. December 8, 2006.

British Columbia Utilities Commission. In the Matter of BC Hydro 2006 Integrated Electricity Plan and Long Term Acquisition Plan. Pre-filed Evidence filed on behalf of the Sierra Club (BC Chapter), Sustainable Energy Association of BC, and Peace Valley Environment Association. October 6, 2006. Testimony addressing the “firming premium” associated with 2006 Call energy, liquidated damages provisions, and wind integration studies.

Maine Joint Legislative Committee on Utilities, Energy and Transportation. Testimony before the Committee in support of an Act to Encourage Energy Efficiency (LD 1931) on behalf of the Maine Natural Resources Council, February 9, 2006. The testimony and related analysis focused on the costs and benefits of increasing the system benefits charge to increase the level of energy efficiency installations by Efficiency Maine.

Nova Scotia Utilities and Review Board (UARB). Testimony filed before the UARB on behalf of the UARB staff, In The Matter of an Application by Nova Scotia Power Inc. for Approval of Air Emissions Strategy Capital Projects. Filed Jaunary 30, 2006. The testimony addressed the application for approval of installation of a flue gas desulphurization system at NSPI’s Lingan station and a review of alternatives to comply with provincial emission regulations.

New Jersey Board of Public Utilities. Direct and Surrebuttal Testimony filed before the Commission addressing the Joint Petition Of Public Service Electric and Gas Company And Exelon Corporation For Approval of a Change in Control Of Public Service Electric and Gas Company And Related Authorizations (the proposed merger), BPU Docket EM05020106. Joint Testimony with Bruce Biewald and David Schlissel. Filed on behalf of the New Jersey Division of the Ratepayer Advocate, November 14, 2005 (direct) and December 27, 2005 (surrebuttal).

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission addressing the proposed Duke – Cinergy merger. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 42873, November 8, 2005.

Illinois Commerce Commission. Direct and Rebuttal Testimony filed before the Commission addressing wholesale market aspects of Ameren's proposed competitive procurement auction (CPA). Testimony filed on behalf of the Illinois Citizens Utility Board in Dockets 05-0160, 05-0161, 05-0162. Direct Testimony filed June 15, 2005; Rebuttal Testimony filed August 10, 2005.

Illinois Commerce Commission. Direct and Rebuttal Testimony filed before the Commission addressing wholesale market aspects of Commonwealth Edison's proposed BUS (Basic Utility Service) competitive auction procurement. Testimony filed on behalf of the Illinois Citizens Utility Board and the Cook County State's Attorney's Office in Docket 05-0159. Direct Testimony filed June 8, 2005; Rebuttal Testimony filed August 3, 2005.

Indiana Utility Regulatory Commission. Responsive Testimony filed before the Commission addressing a proposed Settlement Agreement between PSI and other parties in respect of issues surrounding the Joint Generation Dispatch Agreement in place between PSI and CG&E. Filed on behalf of the Citizens Action Coalition of Indiana, Consolidated Causes No. 38707 FAC 61S1, 41954, and 42359-S1, August 31, 2005.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission in a Fuel Adjustment Clause (FAC) Proceeding concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E, and related issues of PSI lost revenues from inter-company energy pricing policies. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 38707 FAC 61S1, May 23, 2005.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 41954, April 21, 2005.

State of Maine Public Utilities Commission. Testimony filed before the Commission on an Analysis of Eastern Maine Electric Cooperative, Inc.'s Petition for a Finding of Public Convenience and Necessity to Purchase 15 MW of Transmission Capacity from New Brunswick Power and for Related Approvals. Testimony filed jointly with David Schlissel and Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2005-17, July 19, 2005.

State of Maine Public Utilities Commission. Testimony filed before the Commission on an Analysis of Maine Public Service Company Request for a Certificate of Public Convenience and Necessity to Purchase 35 MW of Transmission Capacity from New Brunswick Power. Testimony filed jointly with David Schlissel and Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2004-538 Phase II, April 14, 2005.

Nova Scotia Utilities and Review Board (UARB). Testimony filed before the UARB on behalf of the UARB staff, In The Matter of an Application by Nova Scotia Power Inc. for Approval of an Open Access Transmission Tariff (OATT). Filed April 5, 2005. The testimony addressed various aspects of OATTs and FERC's *pro forma* Order 888 OATT.

Texas Public Utilities Commission. Testimony filed before the Texas PUC in Docket No. 30485 on behalf of the Gulf Coast Coalition of Cities on CenterPoint Energy Houston Electric, LLC. Application for a Financing Order, January 7, 2005. The testimony addressed excess mitigation credits associated with CenterPoint's stranded cost recovery.

Ontario Energy Board. Testimony filed before the Ontario Energy Board, RP-2002-0120, et al., Review of the Transmission System Code (TSC) and Related Matters, Detailed Submission to the Ontario Energy Board in Response To Phase I Questions Concerning the Transmission System Code and Related Matters, October 31, 2002, on behalf of TransAlta Corporation; and Reply Comments for same, November 21, 2002. Related direct and reply filings in response to the Ontario Energy Board's "Preliminary Propositions" on TSC issues in May and June, 2003.

Alberta Energy and Utilities Board. Testimony filed before the Alberta Energy and Utilities Board, in the Matter of the Transmission Administrator's 2001 Phase I and Phase II General Rate Application, no. 2000135, pertaining to Supply Transmission Service charge proposals. Joint testimony filed with Dr. Richard D. Tabors. March 28, 2001. Testimony filed on behalf of the Alberta Buyers Coalition.

Ontario Energy Board. Testimony filed before the Ontario Energy Board, RP-1999-0044, Critique of Ontario Hydro Networks Company's Transmission Tariff Proposal and Proposal for Alternative Rate Design, January 17, 2000. Testimony filed on behalf of the Independent Power Producer's Society of Ontario.

MAJOR PROJECT WORK – BY CATEGORY

Electric Utility Industry Regulatory and Legislative Proceedings

For the staff of the Nova Scotia Utility and Review Board, conducted an economic analysis of the proposed installation of flue gas desulphurization equipment by Nova Scotia Power, Inc., and alternatives to the installation, to conform to Nova Scotia provincial emission regulations. (2005-2006)

For the staff of the Nova Scotia Utility and Review Board, analyzed a proposed Open Access Transmission Tariff by Nova Scotia Power, Inc. (2005)

For the Maine Office of Public Advocate, analyzed multiple aspects of the proposed installation of a second 345 kV tie line between Maine and New Brunswick. The analyses focused on the impacts to Northern Maine electric consumers. (2005)

Electric Utility Industry Restructuring

For the Citizens Action Coalition of Indiana, analyzed the proposed merger between Duke and Cinergy, with a focus on global protections available for PSI ratepayers and the allocation of projected merger cost and savings. (2005)

For the Citizens Action Coalition of Indiana, analyzed the termination of the Joint Generation Dispatch Agreement between Cincinnati Gas and Electric and PSI with a focus on PSI ratepayer impacts. (2005)

For TransAlta Energy Corporation, developed an issues and information paper on recent Ontario and Alberta market development efforts, focusing on the likely high-level impacts associated with day-ahead and capacity market mechanisms considered in each of those regions. (2004)

For a wholesale energy market stakeholder, participate in New England and PJM RTO markets and market implementation committee meetings, review and summarize material, and advocate on behalf of client on selected market design issues. (2004) Performed similar activities for separate client in New England. (2001)

For a group of potential generation investors in Ontario, analyzed the government’s proposed wholesale and retail market design changes and produced an advocacy report for submission to the Ontario Ministry of Energy. The report emphasized, among other things, the importance of retaining a competitive wholesale market structure. (2004)

For a large midwestern utility, supported multiple rounds of direct and rebuttal testimony to the US FERC by Dr. Richard Tabors on the proposed start-up of LMP markets in the Midwest ISO utility service territories. Testimony substance included PJM-MISO seams concerns, FTR allocation options, grandfathered transactions incorporation, FTR and energy market efficiency impacts, and other wholesale market and MISO transmission tariff design issues. Testimony also included quantitative analysis using GE MAPS security-constrained dispatch model runs. (2003-2004)

For the Independent Power Producers Society of Ontario, with TCA Director Seabron Adamson, developed a position paper on resource adequacy mechanisms for the Ontario electricity market. (2003)

For TransAlta Energy Corp., provided direct and reply testimony to the Ontario Energy Board on the Transmission System Code review process. Analyzed and reported on transmission “bypass” and network cost responsibility issues. (2002-2003)

For a commercial electricity marketer in Ontario, with TCA staff, analyzed Ontario market rules for interregional transactions, focusing primarily on the Michigan and New York interties, and assessed the current Ontario electricity market policy related to “failed intertie transactions”. (2002)

For ESBI Alberta Ltd., then Transmission Administrator (TA) of Alberta, served as a key member of the TCA team exploring congestion management issues in the Province, and providing guidance to the TA in presenting congestion management options to Alberta stakeholders, with a particular focus on new transmission expansion pricing and cost allocation issues. (2001)

For a coalition of power producers and marketers in Alberta, filed joint expert witness testimony with Dr. Tabors on the nature of certain transmission access charges associated with supply transmission service. (2001)

For a prospective market participant, served as a core member of the project team that developed summary reports on the New York, New England and PJM wholesale electricity spot market structures. The reports focused on market structure fundamentals, historical transmission flow patterns, forecasted transmission congestion and costs, transmission availability and FTR valuation and market results. (2001)

For the ERCOT ISO, served as a key TCA team member helping to develop and assemble a set of protocols to guide the principles, operation and settlement of the forthcoming Texas competitive wholesale electricity market. (2000)

For the Independent Power Producer’s Society of Ontario, served as expert witness and filed evidence with the Ontario Energy Board supporting an alternative transmission tariff design, and critiquing Ontario Hydro Networks Company’s (OHNC) proposed rate structure. Also a member of OHNC’s Advisory Team on net versus gross billing issues and a leading proponent of a progressive, embedded-generation-friendly tariff structure. (1999-2000)

For a large midwestern utility, designed transmission tariff and wholesale market structures consistent with the proposed establishment of an Independent Transmission Company paradigm for transmission operations. (1999-2000)

For a coalition of independent power producers and marketers in Alberta, helped develop evidence submitted by Dr. Tabors and Dr. Steven Stoft with the Alberta Energy and Utilities Board supporting an alternative to ESBI’s proposed transmission tariff. The evidence critiqued the fairness and efficiency of ESBI’s proposed tariff, and offered a simple alternative to deal with Alberta’s near-term southern supply shortage. (1999)

For Enron Canada Corp., provided ongoing technical support and policy advice during the tenure of the Ontario Market Design Committee (MDC). Presented material on congestion pricing before the committee, and submitted technical assessments of most wholesale market development issues. (1998-1999)

Member of the Ontario Wholesale Market Design Technical Panel. The panel’s responsibilities included refinement of the wholesale market design as specified by the Market Design

Committee, and specification of the market's initial operating requirements. Also served on two sub-panels: bidding and scheduling; and ancillary services. (1998-1999)

For Enron Canada Corp, assessed the generation markets in Ontario and Alberta and recommended policies for maximizing competitive market mechanisms and minimizing stranded cost burdens. Authored reports on stranded costs in Ontario, and on the legislated hedges structure in Alberta. (1997 - 1998)

For an independent power producer, assessed New England markets for electricity and assisted in valuation of generation assets for sale. (1997)

In support of testimony filed by CCEM (Coalition for Competitive Electric Markets) with the FERC, assessed alternative transmission pricing and wholesale market structures proposed for the NY, NE and PJM regions. The filings proposed market mechanisms to produce competitive wholesale electric energy markets and zonal-based transmission pricing structures. (1996-1997)

Electric Utility Mergers and Market Power Analysis

For the New Jersey Ratepayer Advocate, provided jointly sponsored expert testimony (with Bruce Biewald and David Schlissel) on the potential market power effects of the proposed Exelon-PSEG merger. (2005-2006)

For the Citizens Utility Board (Illinois), provided direct and rebuttal testimony on potential market power and transmission impacts and other issues associated with ComEd's proposal to procure standard offer power through a market-based auction process. (2005)

For the Citizens Utility Board and other clients (Illinois), provided direct and rebuttal testimony on issues associated with Ameren's proposal to procure standard offer power through a market-based auction process. (2005)

In support of FERC-filed testimony by Dr. Richard Tabors, conducted a detailed examination of the accessibility of transmission service for wholesale energy market participants on the American Electric Power and Central and Southwest transmission systems. This included evaluating all transmission service requests made over the OASIS for the first six months of 1998 for the two utility systems, and a subsequent, more detailed assessment of AEP's transmission system use during all of 1998. (1998-1999)

For a US western electric utility, served as a member of the team that conducted detailed production cost modeling and strategic market assessment to determine the extent or absence of market power held by the client. (1998)

For an independent power producer, supported FERC-filed testimony on market power issues in the New York State energy and capacity markets. This included detailed supply-curve assessment of existing generation assets within the New York Power Pool. (1997)

Worked with a local economic consulting firm for a Western State public agency in conducting an analysis of the projected savings of a series of proposed electric and gas utility mergers. (1997)

For a southwestern utility company, supported CRA in conducting an analysis of the competitive effects of a proposed electric utility merger. For a northwestern utility company, analyzed the competitive effects of a proposed electric utility merger. (1995-1996)

For the Massachusetts Attorney General's Office, conducted a study of the potential for market power abuse by generators in the NEPOOL market area. (1996)

Energy Efficiency and Demand Side Management

For the Maine Office of the Public Advocate, evaluated the ability of DSM and distributed generation to affect the need for transmission and distribution system reinforcement in the Saco Bay area of Central Maine Power's service territory. (2007)

For the Natural Resources Council of Maine, analyzed the costs and benefits of increasing the system benefits charge (SBC) in Maine to increase efficiency installations by Efficiency Maine. Testimony before the Maine Joint Legislative Committee on Energy and Utilities. (2006)

For Southern California Edison (SCE), working as a sub-contractor to Sargent and Lundy, analyzed the potential for an interstate transfer of a DSM resource between the desert southwest and California. For the same project, also analyzed transmission impacts of various alternatives to replace power supply from the currently closed Mohave generation station for SCE. (2005)

For two separate large New England utilities, conducted impact evaluations of large commercial and industrial sector DSM programs. (1994-1996)

For a New England utility, worked on the project team developing a set of DSM evaluation master plans for incentive-type and third-party-contracting type DSM programs (1994)

For EPRI, wrote an overview of the status of DSM information systems and the potential effects of an increasingly competitive utility environment. (1993)

For two separate large New England utilities, helped to develop competitive procurement documents (DSM RFPs) for filing before the Massachusetts Department of Public Utilities. (1993, 1994)

For a midwestern utility, conducted a trade ally study designed to determine the influence of trade allies on the market for energy efficient lighting and motor equipment. (1992-1993)

DSM Implementation

Conducted detailed site visits and suggested efficiency improvement strategies for over 1,000 commercial, industrial and institutional buildings in Rhode Island. Performed end-use energy analysis and coordinated implementation of improvements. Worked with local utility DSM program personnel to educate building owners on DSM program opportunities. (1987-1992)

Energy Modeling

For various clientele, worked closely with the TCA GE MAPS modeling group on various facets of security-constrained dispatch modeling of electric power systems across the US and Canada. Specific tasks included assisting in designing MAPS model run parameters (e.g., base case and alternative scenarios specification); proposing modeling designs to clients; supporting input data gathering; interpreting model results; and writing summary reports, memos & testimony describing the results. (2002-2004)

For a group of potential electricity supply investors in Ontario, modeled the impact of proposed generation plant phaseout trajectories on investment requirements for new supply in Ontario. (2004)

For the Independent Power Producer's Society of Ontario, conducted a retrospective quantitative analysis of the Ontario market energy and ancillary service prices during the 15 months of the new wholesale market to determine the extent of infra-marginal rents available that could have supported entry for new generation. (2003)

In support of proposals to the US Dept. of Defense for military housing privatization, performed DOE-2 model runs using an online tool; and created a spreadsheet modeling tool to analyze the efficiency and cost effectiveness of new and renovated residential construction for base housing. Performed life-cycle utility cost analysis and prepared energy plans specifying building shell, equipment and appliance efficiency measures at 15 separate Army, Navy, and Air Force installations around the nation. (2001-2003)

For the Independent Power Producer's Society of Ontario, conducted a rate impact analysis of Ontario Hydro Networks Company proposed transmission tariff. (1999-2000)

For the University of Maryland at Baltimore, conducted a life-cycle cost analysis of alternative proposals for district-type thermal energy provision, comparing existing steam delivery systems to new hot-water systems. (1998)

For the UMass Medical Center (Worcester), conducted an energy use and cost allocation analysis of a large hospital complex to assist in choosing among electric and thermal energy supply options. (2000)

For an independent power producer, developed a spreadsheet-based tool to assess the rate impact of a clean coal facility in Maryland compared to alternative gas-fired supply options. (1996-1997)

For a private consulting firm, examined electric end-use and generation capacity information in seven industry energy models and reported the sensitivities of each model to varying levels of input aggregation. (1995)

For a private industrial firm in Virginia, developed a Monte-Carlo simulation-based spreadsheet model to solve a capital budgeting problem involving long-term choice of industrial boiler equipment. (1995)

For a New England utility, developed a spreadsheet model to help determine economic decision-making processes used by energy service companies when delivering third-party procured DSM. (1995)

Petroleum and Natural Gas Industry Analysis

For a private independent power producer, conducted an analysis of the rate impacts of the Warrior Run clean coal (fluidized bed combustion) power plant in Maryland under various assumptions of natural gas prices and environmental regulation scenarios. (1996-1997)

For a British consulting firm, researched and presented findings on the current status of natural gas restructuring efforts in the US and their impact on regional US markets for power generation. (1996)

For a Canadian law firm representing Native Canadian interests, conducted a detailed analysis of natural gas netback pricing for Alberta gas into US Midwest and West Coast markets over a thirty-year period. (1995)

For a US natural gas pipeline consortium, performed an econometric analysis of the demand for natural gas in the state of Florida. (1992-1993)

PAPERS, PUBLICATIONS AND PRESENTATIONS

Interstate Transfer of a DSM Resource: New Mexico DSM as an Alternative to Power from Mohave Generating Station. Jointly authored with Tim Woolf, Bill Steinhurst and Bruce Biewald. Presented at the 2006 ACEEE Summer Study on Energy Efficiency in Buildings and published in the proceedings. (2006)

SMD and RTO West: Where are the Benefits for Alberta? Keynote Paper prepared for the 9th Annual Conference of the Independent Power Producers Society of Alberta, with Dr. Richard D. Tabors, March 7, 2003.

A Progressive Transmission Tariff Regime: The Impact of Net Billing, presentation at the Independent Power Producer Society of Ontario annual conference, November 1999.

Tariff Structure for an Independent Transmission Company, with Richard D. Tabors, Assef Zobian, Narasimha Rao, and Rick Hornby, TCA Working Paper 101-1099-0241, November 1999.

Transmission Congestion Pricing Within and Around Ontario, presentation at the Canadian Transmission Restructuring Infocast Conference, Toronto, June 2-4, 1999.

The Restructured Ontario Electricity Generation Market and Stranded Costs. An internal company report presented to the Ontario Ministry of Energy and Environment on behalf of Enron Capital and Trade Resources Canada Corp., February 1998.

Alberta Legislated Hedges Briefing Note. An internal company report presented to the Alberta Department of Energy on behalf of Enron Capital and Trade Resources Canada, January 1998.

Generation Market Power in New England: Overall and on the Margin. Presentation at Infocast Conference: New Developments in Northeast and Mid-Atlantic Wholesale Power Markets, Boston, June 1997.

The Market for Power in New England: The Competitive Implications of Restructuring. Prepared for the Office of the Attorney General, Commonwealth of Massachusetts, by Tabors Caramanis & Associates with Charles River Associates, April 1996. R. Fagan was a key member of the team that produced the report.

Estimating DSM Impacts for Large Commercial and Industrial Electricity Users. Lead investigator and author, with M. Gokhale, D.S. Levy, P.J. Spinney, G.C. Watkins. Presented at The Seventh International Energy Program Evaluation Conference, Chicago, Illinois, August 1995, and published in the Conference Proceedings.

Sampling Issues in Estimating DSM Savings: An Issue Paper for Commonwealth Electric. Prepared with G.C. Watkins, Charles River Associates. Report for COM/Electric System, filed with the MA Dept. of Public Utilities (MDPU), April 28, 1995, Docket # DPU 95-2/3-CC-l.

Demand-side Management Information Systems (DSMIS) Overview. Electric Power Research Institute Technical Report TR-104707. Robert M. Fagan and Peter S. Spinney, principal investigators, prepared by Charles River Associates for EPRI, January 1995.

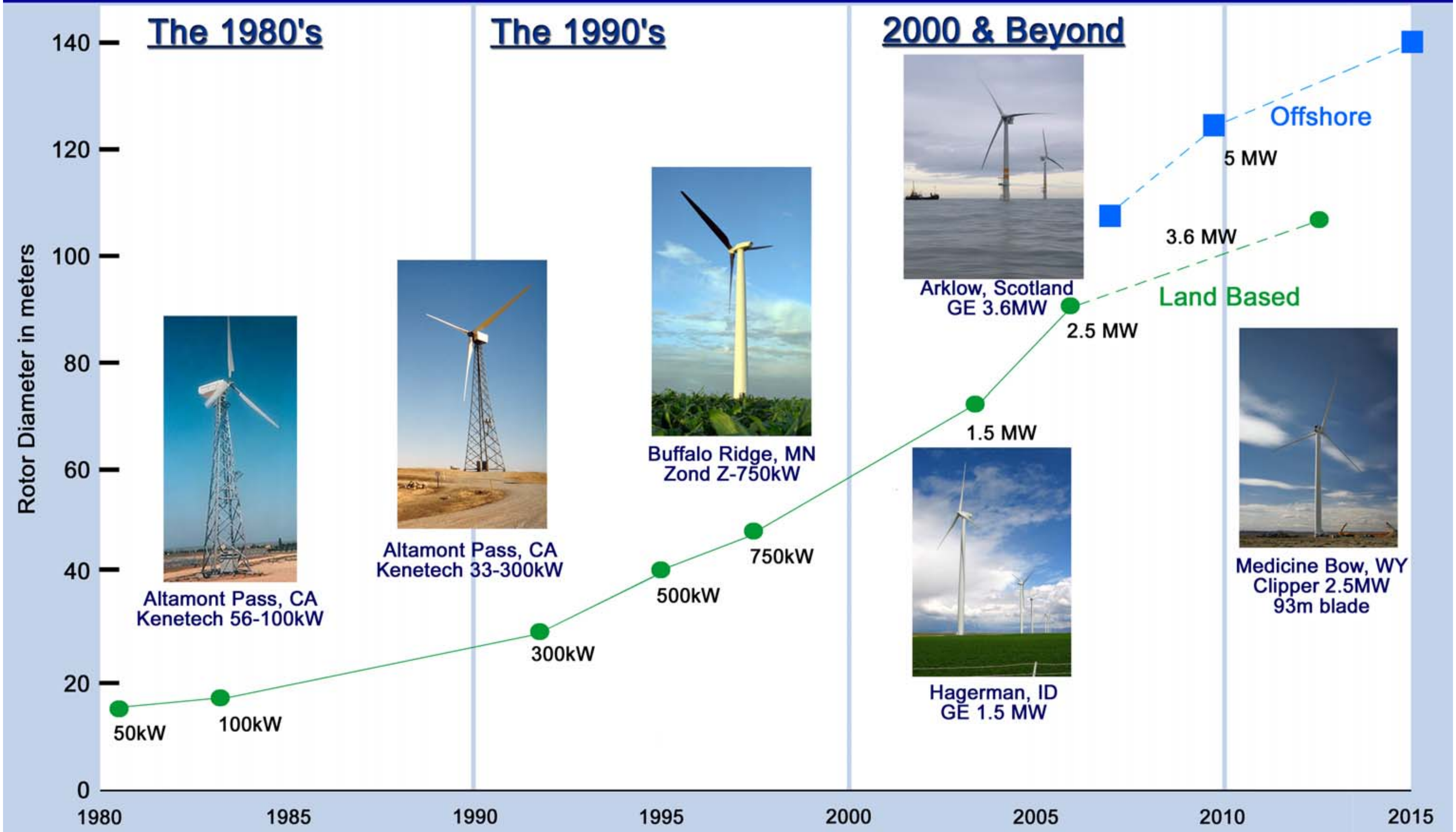
Impact Evaluation of Commonwealth Electric's Customized Rebate Program. With P.J. Spinney and G.C. Watkins. Charles River Associates, Initial and Updated Reports, April 1994, April 1995, and April 1996.1995 updated report filed with the MDPU, April28, 1995, Docket # DPU 95-2/3-CC-I. The initial report filed with the MDPU, April 1, 1994.

Northeast Utilities Energy Conscious Construction Program (Comprehensive Area): Level I and Level II Impact Evaluation Reports. With Peter S. Spinney (CRA) and Abbe Bjorklund (Energy Investments). Charles River Associates Reports prepared for Northeast Utilities, June and July 1994.

The Role of Trade Allies in C&I DSM Programs: A New Focus for Program Evaluation, Paper authored by Peter J. Spinney (Charles River Associates) and John Peloza (Wisconsin Electric Power Corp.). Presented by Bob Fagan at the Sixth International Energy Evaluation Conference, Chicago, Illinois, August 1993.

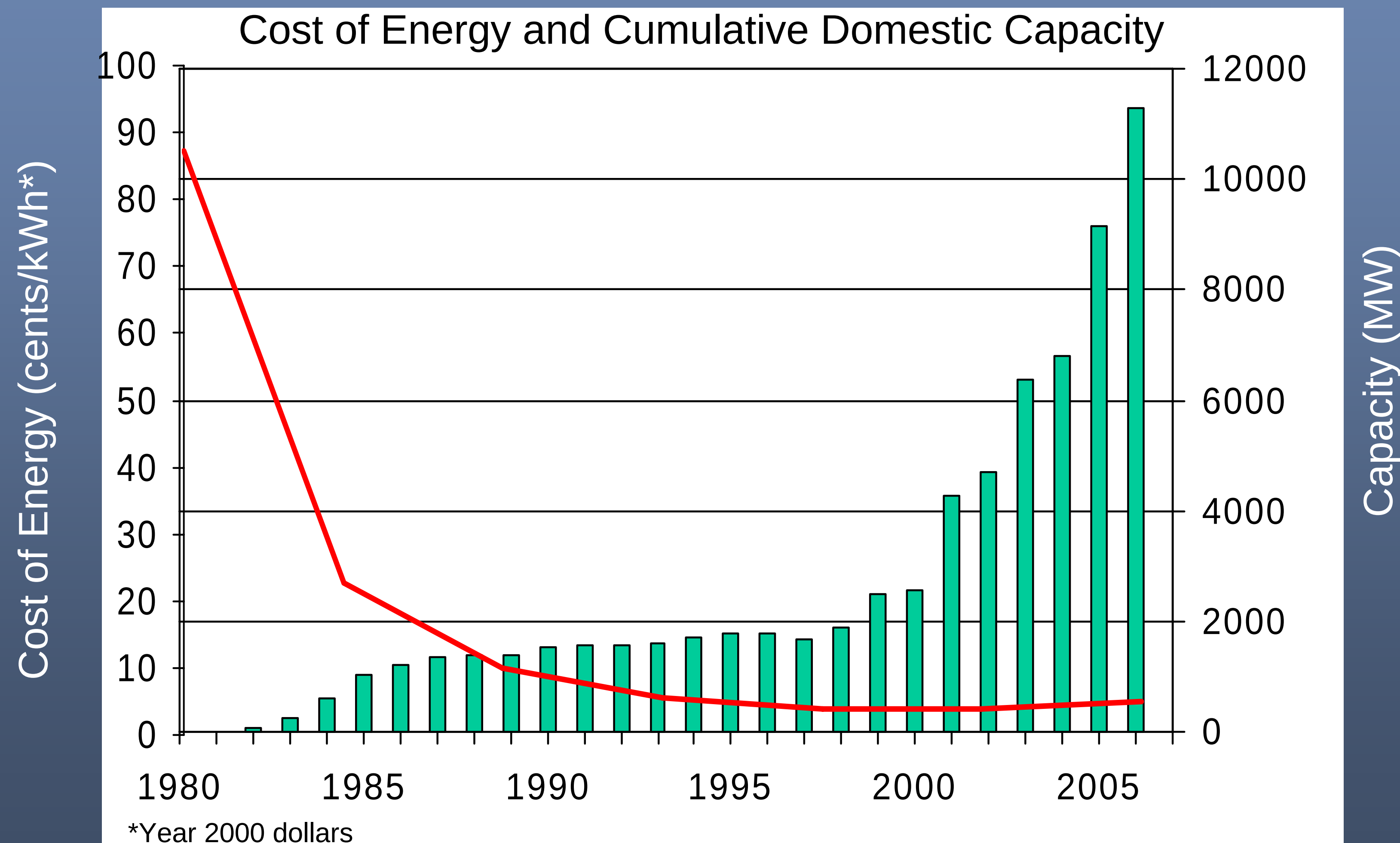
Resume dated April 2007.

Evolution of U.S. Commercial Wind Technology



Source: Larry Flowers, NREL, Wind Powering America Update, April 3, 2007, Slide 3. Available at http://www.eere.energy.gov/windandhydro/windpoweringamerica/filter_detail.asp?itemid=746

Capacity & Cost Trends

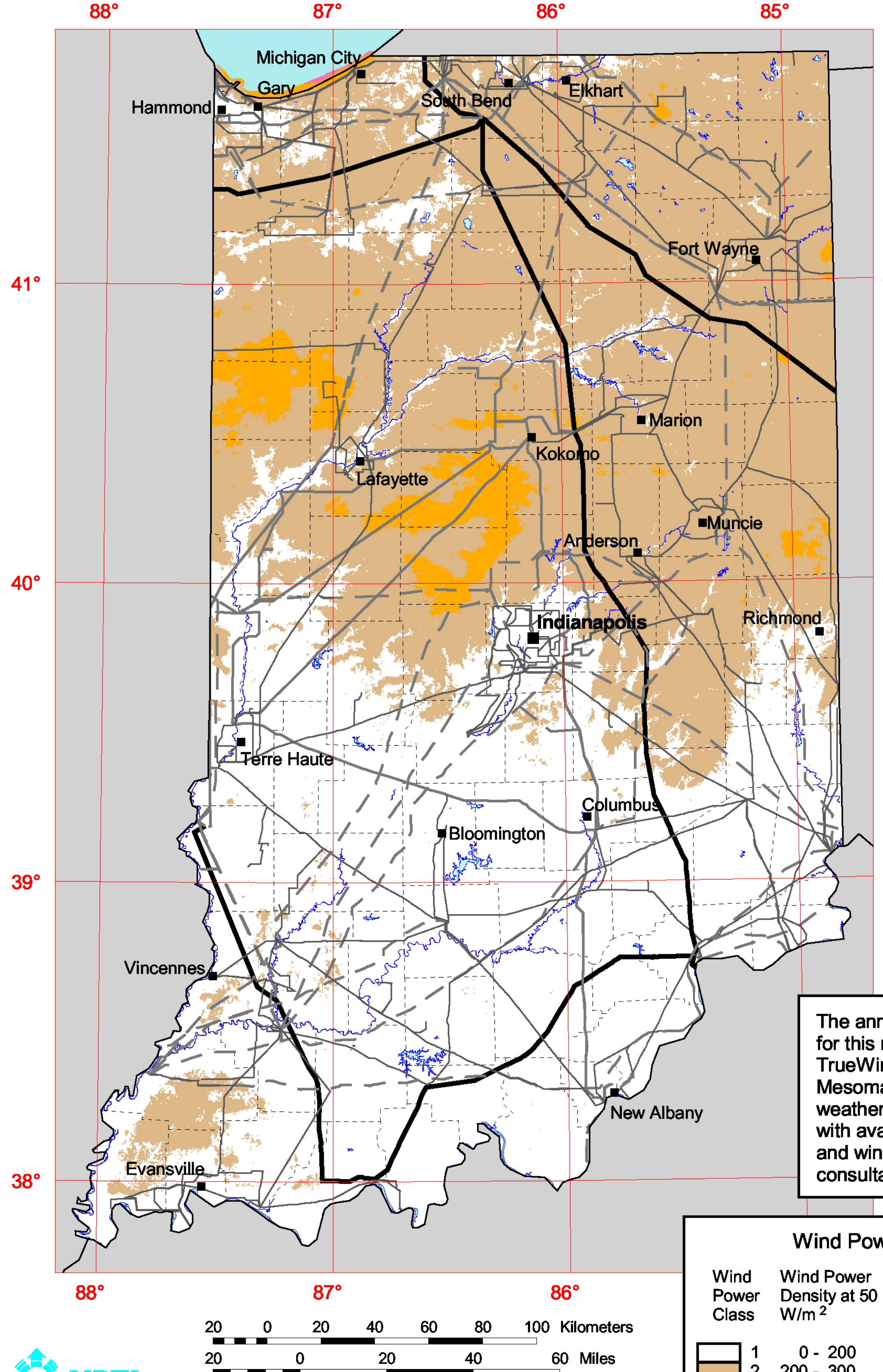


Increased Turbine Size - R&D Advances - Manufacturing Improvements

Larry Flowers, NREL, Wind Powering America Update, April 3, 2007, Slide 4. Available at http://www.eere.energy.gov/windandhydro/wi

IURC Cause # 43114 Exhibit RMF-4

Indiana - 50 m Wind Power



Transmission Line*
Voltage (kV)

- 69
- 115 - 161
- 230
- 345
- 765

* Source: POWERmap, ©2003 Platts, a Division of the McGraw-Hill Companies

The annual wind power estimates for this map were produced by TrueWind Solutions using their Mesomap system and historical weather data. It has been validated with available surface data by NREL and wind energy meteorological consultants.

Wind Power Classification

Wind Power Class	Wind Power Density at 50 m W/m ^{2}	Wind Speed[a] at 50 m m/s	Wind Speed[a] at 50 m mph
1	0 - 200	0.0 - 5.6	0.0 - 12.5
2	200 - 300	5.6 - 6.4	12.5 - 14.3
3	300 - 400	6.4 - 7.0	14.3 - 15.7
4	400 - 500	7.0 - 7.5	15.7 - 16.8

[a] Wind speeds are based on a Weibull k of 2.0.

U.S. Department of Energy
National Renewable Energy Laboratory

02-JUL-2004 1.1.1

Wind Energy Resource Maps of Indiana

Prepared for:

Indiana Department of Commerce
Energy Policy Division
One North Capitol #700
Indianapolis, IN 46204-2248
Attention: Philip Powlick

Prepared by:

TrueWind Solutions, LLC
CESTM, 255 Fuller Road
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Principal Author: Michael Brower
Reviewer: Staci Clark

March 15, 2004

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EXECUTIVE SUMMARY IV

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EXECUTIVE SUMMARY

This report describes a wind-mapping project conducted by TrueWind Solutions for the Indiana Department of Commerce. Using the MesoMap system, TrueWind has produced maps of mean wind speed in Indiana for heights of 30, 50, 70, and 100 m above ground, as well as a map of wind power at 50 m. TrueWind has also produced data files of the predicted wind speed frequency distribution and speed and energy by direction. The maps and data files are provided on a CD with the ArcReader software, which will enable users to view, print, copy, and query the maps and wind rose data.

The MesoMap system consists of an integrated set of atmospheric simulation models, databases, and computers and storage systems. At the core of MesoMap is MASS (Mesoscale Atmospheric Simulation System), a numerical weather model, which simulates the physics of the atmosphere. MASS is coupled to a simpler wind flow model, WindMap, which is used to refine the spatial resolution of MASS and account for localized effects of terrain and surface roughness. MASS simulates weather conditions over a region for 366 historical days randomly selected from a 15-year period. When the runs are finished, the results are input into WindMap. In this project, the MASS model was run on a grid spacing of 1.7 km and WindMap on a grid spacing of 200 m.

In collaboration with the National Renewable Energy Laboratory, TrueWind subsequently validated the wind maps using data from 22 stations. The data were first extrapolated to a height of 50 m. The predicted wind speeds are on average about 0.3 m/s higher than the observed/extrapolated speeds. The root-mean-square discrepancy is 0.6 m/s, or about 10% of the average of all the stations. After accounting for uncertainty in the data, we estimated the map error margin (one sigma) to be 0.5 m/s, or 8.5%. The error margin in meters/second is comparable to that obtained in other MesoMap projects, but in percentage terms it is somewhat larger than usual. This is mainly because of the moderate average speed (5.9 m/s at 50 m) of the Indiana stations. In addition, the validation sample includes data from five stations which have rather low mean speeds compared to other stations in their vicinity. If these stations are excluded, the mean bias becomes 0.1 m/s, and the rms discrepancy becomes 0.4 m/s, or 6%, which is comparable to the error margin of the data.

While the validation confirmed the overall accuracy of the maps, it also revealed some areas where MesoMap appears to have either underestimated or overestimated the wind resource to a moderate degree. With the agreement of NREL, we adjusted the predicted wind speed and power in parts of central and southwestern Indiana.

The wind maps show that the best wind resource in Indiana is found in the north-central part of the state. The mean wind speed at 50 m height between Indianapolis, Kokomo, and Lafayette, and to the northwest of Lafayette, is predicted to be in the range of 6.5 to 7 m/s, and the mean wind power is predicted to be about 250 to 350 W/m^2, or NREL class 2 to 3. In the rest of northern Indiana, the wind speed tends to be around 0.5 m/s lower, and the wind power is a solid class 2. In southern Indiana, a wind speed of 4.5 to 6 m/s and a wind power class of 1 to 2 prevails. The main reason for this wind resource distribution pattern is that the land is much more forested in the southern half of the state than in the northern half. Topography also plays a role, as does the track of the jet stream.

1. INTRODUCTION

The Indiana Department of Commerce is interested in assessing the wind resource of Indiana and finding suitable sites for wind energy projects. Conventional field techniques of wind resource assessment can be time consuming, however, and often depend heavily on local meteorological expertise as well as the availability of reliable and representative wind measurements. Conventional wind flow models, on the other hand, have often proven inaccurate in complex wind regimes, and even in moderate terrain their accuracy can decline substantially with distance from the nearest available reference mast.

Mesoscale-microscale modeling techniques offer a solution to these challenges. By combining a sophisticated numerical weather model capable of simulating large-scale wind patterns with a microscale wind flow model responsive to local terrain and surface conditions, they enable the mapping of wind resources over large regions with much greater accuracy than has been possible in the past. In addition, they do not require surface wind data to make reasonably accurate predictions. While on-site measurements are still required to confirm the predicted wind resource at any particular location, mesoscale-microscale modeling can greatly reduce the time and cost to identify and evaluate potential wind project sites.

TrueWind Solutions has been the world leader in the development of mesoscale-microscale mapping techniques, having introduced the MesoMap system in the late 1990s. In the past five years, MesoMap has been applied in nearly 30 countries on four continents. In North America alone, MesoMap has been used to map over 30 US states and several provinces of Canada and states of Mexico.

The objective of the current project was to use MesoMap to create high-resolution wind resource maps of Indiana and to provide wind resource data in a format enabling the Indiana Department of Commerce to assess potential sites in a GIS. These objectives have been met. In the following sections, we describe the MesoMap system and mapping process in detail; how MesoMap was applied in this project; the validation process and results; the final wind maps and data files; and guidelines for the use of the maps.

2. DESCRIPTION OF THE MESOMAP SYSTEM

The MesoMap system has three main components: models, databases, and computer systems. These components are described below.

2.1. Models

At the core of the MesoMap system is MASS (Mesoscale Atmospheric Simulation System), a numerical weather model that has been developed over the past 20 years by TrueWind partner MESO, Inc., both as a research tool and to provide commercial weather forecasting services. MASS simulates the fundamental physics of the atmosphere including conservation of mass, momentum, and energy, as well as the moisture phases, and it contains a turbulent kinetic energy module that accounts for the effects of viscosity and thermal stability on wind shear. As a dynamical model, MASS simulates the evolution of atmospheric conditions in time steps as short as a few seconds. This creates great computational demands, especially when running at high resolution. Hence MASS is usually coupled to a simpler but much faster program, WindMap, a mass-conserving wind flow model. Depending on the size and complexity of the region and requirements of the client, WindMap is used to improve the spatial resolution of the MASS simulations to account for the local effects of terrain and surface roughness variations.

2.2. Data Sources

The MASS model uses a variety of online, global, geophysical and meteorological databases. The main meteorological inputs are reanalysis data, rawinsonde data, and land surface measurements. The reanalysis database – the most important – is a gridded historical weather data set produced by the US National Centers for Environmental Prediction (NCEP) and National Center for Atmospheric Research (NCAR). The data provide a snapshot of atmospheric conditions around the word at all levels of the atmosphere in intervals of six hours. Along with the rawinsonde and surface data, the reanalysis data establish the initial conditions as well as updated lateral boundary conditions for the MASS runs. The MASS model itself determines the evolution of atmospheric conditions within the region based on the interactions among different elements in the atmosphere and between the atmosphere and the surface. Because the reanalysis data are on a relatively coarse, 200 km grid, MASS is run in several nested grids of successfully finer mesh size, each taking as input the output of the previous nest, until the desired grid scale is reached. This is to avoid generating noise at the boundaries that can result from large jumps in grid cell size. The outermost grid typically extends several thousand kilometers.

The main geophysical inputs are elevation, land cover, vegetation greenness (normalized differential vegetation index, or NDVI), soil moisture, and sea-surface temperatures. The global elevation data normally used by MesoMap were produced by the US Geological Survey in a gridded digital elevation model, or DEM, format from a variety of data sources.[1] The US Geological Survey, the University of Nebraska, and the European Commission's Joint Research Centre (JRC) produced the global land cover data in a cooperative project. The land cover classifications are derived from the interpretation of Advanced Very High Resolution Radiometer (AVHRR) data – the same data used to calculate the NDVI. The model translates both land cover and NDVI data into physical parameters such as surface roughness, albedo, and emissivity. The nominal spatial resolution of all of these data sets is 1 km. Thus, the standard output of the MesoMap system is a 1 km gridded wind map. However, much higher resolution maps can be produced where the necessary topographical and land cover data are available. In the United States, the resolution is typically 100 to 400 m.

2.3. Computer and Storage Systems

The MesoMap system requires a very powerful set of computers and storage systems to produce wind resource maps at a sufficiently high spatial resolution in a reasonable amount of time. To meet this need TrueWind Solutions has created a distributed processing network consisting of 94 Pentium II processors and 3 terabytes of hard disk storage. Since each day simulated by a processor is entirely independent of other days, a project can be run on this system up to 94 times faster than would be possible

[1]The US Defense Department's high-resolution Digital Terrain Elevation Data set is the principal source for the global 1 km elevation. Gaps in the DTED data set were filled mainly by an analysis of 1:1,000,000 scale elevation contours in the Digital Chart of the World (now called VMAP).

with any single processor. To put it another way, a typical MesoMap project that would take two years to run on a single processor can be completed in just one week.

2.4. The Mapping Process

The MesoMap system creates a wind resource map in several steps. First, the MASS model simulates weather conditions over 366 days selected from a 15-year period. The days are chosen through a stratified random sampling scheme so that each month and season is represented equally in the sample; only the year is randomized. Each simulation generates wind and other weather variables (including temperature, pressure, moisture, turbulent kinetic energy, and heat flux) in three dimensions throughout the model domain, and the information is stored at hourly intervals. When the runs are finished, the results are compiled into summary data files, which are then input into the WindMap program for the final mapping stage. The two main products are usually (1) color-coded maps of mean wind speed and power density at various heights above ground and (2) data files containing wind speed and direction frequency distribution parameters. The maps and data can then be compared with land and ocean surface wind measurements, and if significant discrepancies are observed, adjustments to the wind maps can be made.

2.5. Factors Affecting Accuracy

In our experience, the most important sources of error in the wind resource estimates produced by MesoMap are the following:

- Finite grid scale of the simulations
- Errors in assumed surface properties such as roughness
- Errors in the topographical and land cover data bases

The finite grid scale of the simulations results in a smoothing of terrain features such as mountains and valleys. For example, a mountain ridge that is 2000 m above sea level may appear to the model to be only 1600 m high. Where the flow is forced over the terrain, this smoothing can result in an underestimation of the mean wind speed or power at the ridge top. Where the mountains block the flow, on the other hand, the smoothing can result in an overestimation of the resource as the model understates the blocking effect. The problem of finite grid scale can be solved by increasing the spatial resolution of the simulations, but at a cost in computer processing and storage.

Errors in the topographical and land cover data can obviously affect wind resource estimates. While elevation data are usually reliable, errors in the size and location of terrain features nonetheless occur from time to time. Errors in the land cover data are more common, usually as a result of the misclassification of aerial or satellite imagery. It has been estimated that the global 1 km land cover database used in the MASS simulations is about 70% accurate. Where possible, more accurate and higher resolution land cover databases should be used in the WindMap stage of the mapping process to correct errors introduced in the MASS simulations. In the United States, we use a 30 m gridded Landsat-derived land cover database for this purpose; a similar 250 m database, called Corine, is available for most of Western Europe.

Even if the land cover types are correctly identified, there is uncertainty in the surface properties that should be assigned to each type, and especially the vegetation height and roughness. The forest category, for example, may include many different varieties of trees with varying heights and density, leaf characteristics, and other features that affect surface roughness. Cropland may be virtually devoid of trees and buildings, or it may have many windbreaks. Uncertainties like these can be resolved only by acquiring more information about the area through aerial photography or field observation. However this is not practical when (as in this project) the area being mapped is very large.

3. IMPLEMENTATION OF MESOMAP FOR THIS PROJECT

The standard MesoMap configuration was used in this project. MASS was run on the following nested grids:

First (outer) grid level: 30 km
Second (intermediate) grid level: 8 km
Third (inner) grid level: 1.7 km

The usual geophysical and meteorological inputs were used. The WindMap program adjusted the wind resource estimates to reflect local topography and surface roughness changes on a grid spacing of 200 m. For the topographical data, we used the National Elevation Dataset, a digital terrain model produced on a 30 m grid by the US Geological Survey (USGS). For the land cover, we used the National Land Cover Dataset, which is derived from Landsat imagery. It was also produced by the USGS on a 30 m grid.[2] Both data sets are of very high quality.

In converting from land cover to surface roughness, the roughness length values shown in Table 1 were assumed. We believe these values to be typical of conditions in the southwestern states, including Indiana. However the actual roughness could vary a good deal within each class.

Table 1. Range of Surface Roughness Values for Leading Land Cover Types

Description	Roughness (m)
Perennial Snow and Ice	0.003
Cropland	0.03
Grasslands/Herbaceous	0.05
Shrubland	0.07
Deciduous Forest	0.9
Evergreen and Mixed Forest	1.13
Residential and Urban	0.3

The roughness is not the only surface property with a direct effect on near-surface wind speeds. Where there is dense vegetation the wind can skim along the vegetation canopy, thereby displacing the flow above the ground and reducing the speed observed at a fixed height above ground. The displacement height is defined as the

[2] Information on the National Land Cover Data set can be found at the following web address: http://landcover.usgs.gov/nationallandcover.html. Information on the National Elevation Dataset (NED) can be found at http://edcwww.cr.usgs.gov/products/elevation/ned.html.

height at which the wind speed becomes zero in the logarithmic shear formula. The shear formula is as follows:

$$\frac{v_2}{v_1} = \frac{\ln\left(\dfrac{z_2 - d}{z_0}\right)}{\ln\left(\dfrac{z_1 - d}{z_0}\right)}$$

Here, d is the displacement height, z_1 and z_2 are two different heights at which the speed v is measured, and z_0 is the surface roughness (generally much less than z_2 and z_1). Note that according to this formula, when $z_2 = d + z_0$, $v_2 = 0$.

The displacement height is usually estimated to be about two-thirds to three-fourths the maximum vegetation height. For this project, we assumed that the displacement height was 10 times the surface roughness length, which was in turn defined to be approximately 7.5% of the vegetation height. For deciduous forests with a roughness length of 0.9 m, this resulted in a displacement height of 9 m.

The effect of displacement height is to reduce the wind speed observed near the ground and to increase the apparent wind shear measured with respect to ground level. It can also reduce the wind speed measured in small clearings, since the ground appears to be in a "hole" at a depth *d* below the vegetation canopy. The impact of this hole on wind speed diminishes as the clearing becomes large enough for the flow to reach equilibrium with the new effective ground height. As a rule of thumb, the clearing width should be at least 20 times the displacement height for the effect to be negligible at the center of the clearing, but under some conditions the minimum width should be even larger.

4. VALIDATION

The wind resource maps were initially produced without any reference to surface wind measurements. TrueWind and NREL then validated the wind maps by comparing the predicted speed against data from 22 stations. Consulting meteorologists Richard L. Simon and Lucille Olszewski contributed data and insights to the analysis. Seventeen of the stations were at airports. There were also a number of other automated weather stations (PAAWS, Coast Guard, and NOAA) and one 50 m tower instrumented specifically for wind resource assessment. The locations of the stations are shown in the accompanying wind maps.

The validation was carried out in the following steps:

1. Station locations were verified and adjusted, if necessary, by comparing the quoted elevations and station descriptions against the elevation and land cover maps. Where there was an obvious error in position, the station was moved to the nearest point with the correct elevation and surface characteristics.
2. The observed mean speed and power were extrapolated to a common reference height of 50 m using the power law. At the one tall tower, no extrapolation was needed, however it was useful to observe that the measured shear exponent was 0.17. In all other cases, the shear exponent had to be estimated. We relied on model-estimated wind shears in most cases. Assumed shear values ranged from 0.17 to 0.25 at inland sites, with higher shears

predicted in forested and urban environments, and from 0.13 to 0.17 at coastal sites.[3,4]

3. The error margin for each data point was then estimated as a function of two factors: the tower height and the number of years of measurement. The tower height enters the equation because of uncertainty in the wind shear. We assumed an error margin in the shear exponent of 0.03. The number of years of data affects the uncertainty because winds recorded over a short period may not be representative of long-term conditions. A rule of thumb is that a mean speed based on one year of data will be within 10% of the true long-term mean with 90% confidence. This translates into a standard error of 6% for one year of data. We assumed that the annual mean varies randomly according to a normal distribution, and thus the error margin varies inversely with the square root of the number of years. An additional uncertainty of 3% was added to account for possible variations in the characteristics of anemometers and data loggers.
4. The various uncertainties were then combined in a least-squares sum as follows:

$$(1)\ e = \sqrt{0.03^2 + \left(\left(50/H\right)^{0.03} - 1\right)^2 + \left(\frac{0.06}{\sqrt{N}}\right)^2}$$

where H is the height of the anemometer, and N the number of years of measurement. The uncertainty in power (in percentage terms) is assumed to be three times the uncertainty in speed, since the power varies as the cube of the speed.

5. Next, the predicted and measured/extrapolated speed and power were compared, and the map bias (map speed or power minus measured/extrapolated speed or power) was calculated for each point.

Table 2 summarizes the results. The key finding is that the root-mean-square (RMS) discrepancy in speed and power were 0.6 m/s (10.6% of the average observed speed) and 45 W/m^2 (19% of the average observed power), respectively. The wind power RMS discrepancy is larger than the wind speed discrepancy in percentage terms because the power varies as the cube of the speed.

Table 2. Preliminary Validation

	Number of Stations	Mean Bias	RMS Discrepancy	Model Error
Speed	22	0.3 m/s (+5%)	0.63 (10.6%)	0.5 (8.5%)
Power	22	2 W/m^2 (0%)	45 (19%)	NA

[3] A higher shear was assumed at airports where the measurements were taken with ASOS equipment. NREL and TrueWind believe this is justified to compensate for an apparent tendency for ASOS to report lower speeds than other equipment under light wind conditions.

[4] The power shear exponent is assumed to be 3(α-0.03), where α is the speed shear exponent. The reason for the reduction in effective shear, compared to assuming that the power goes strictly as the cube of the speed, is that the speed frequency distribution tends to become narrower with height above ground because the shear is often higher under light wind conditions.

The RMS discrepancy reflects errors both in the model and the data, and thus it tends to overstate the error of the maps alone. The model error is estimated by subtracting (in a least-squares sense) the standard error of the data (e_{DATA}) from the total RMS discrepancy (e_{TOTAL}):

$$(2)\quad e_{MODEL} \approx \sqrt{e_{TOTAL}^2 - e_{DATA}^2}$$

This equation assumes that the errors in the model and data are random, normally distributed, and independent of one another. Using this equation, the speed error for the model alone is found to be 0.5 m/s, or 8.5%. The power error is undefined because the rms discrepancy is slightly smaller than the estimated error margin of the data.

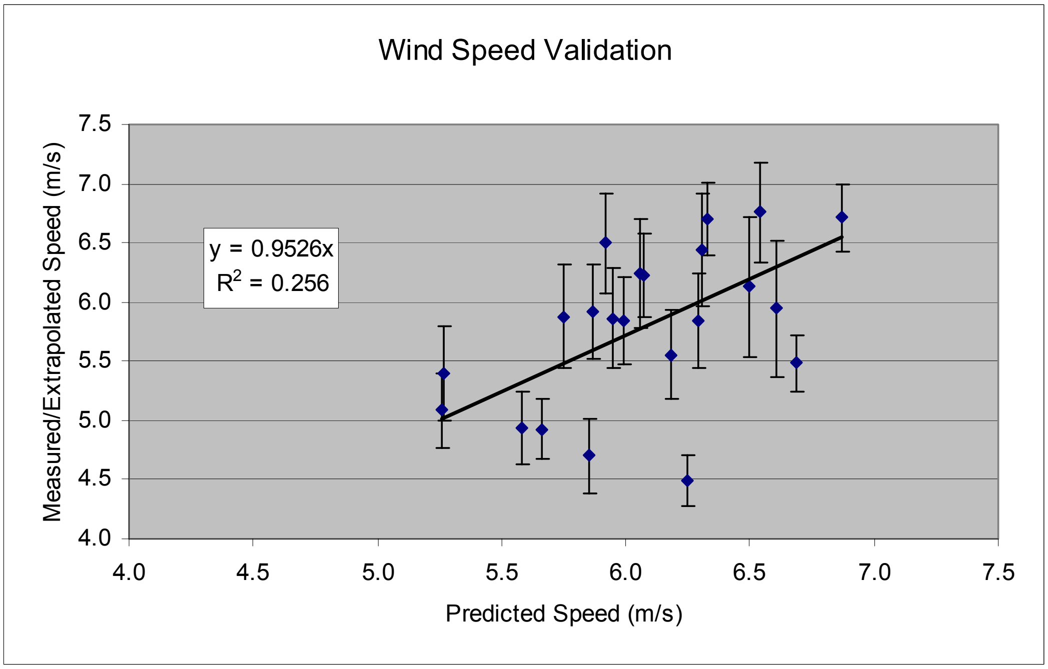
The scatter plots in Figure 1 compare the predicted and measured-extrapolated wind speed and power at 50 m height. The linear trend lines, which are forced through the origin, confirm that the map speeds are about 5% higher than the observed/extrapolated speeds on average, while the map power shows much less bias and higher r^2 value.

Although the agreement between model and data is not bad overall, the percentage errors shown in Table 1 are somewhat larger than usual for MesoMap projects. (The typical model error is 5-7%.) In addition, the scatter plots show several outlying data points where the model and data disagree to a much larger extent than the data error margin should allow.

Our analysis suggests two main reasons for these problems. First, the average observed wind speed (extrapolated to 50 m) among the 22 stations in Indiana was moderate – only about 5.9 m/s. Since model errors, in meters per second, tend to be fairly constant as a function of speed, the lower the average speed, the higher the average percentage error. To take a contrasting example, in our California wind-mapping project, the average model error was 0.5 m/s (about the same as Indiana's), but since the average observed speed was 6.9 m/s, the percentage error was only 7%.

Second, the data for a handful of stations appear to be unreliable. We deduced this by comparing the measurements from stations located in the same general vicinity. The most obvious case is Anderson Airport. Despite being about 25 km southwest of Muncie Airport, and at very nearly the same elevation (280 m), Anderson's measured/extrapolated speed at 50 m is over 2 m/s below that of Muncie (4.5 v. 6.7 m/s) and its measured/extrapolated power is about 170 W/m^2 lower (137 v. 308 W/m^2). Given the relatively flat terrain, it is unlikely that the difference reflects a real variation in the wind resource. Rather, the Anderson Airport mast was probably obstructed in some way. Eagle Creek Airport appears to suffer a similar problem (4.7 m/s versus 5.8 m/s at Fort Wayne 12 km to the south), as does Michigan City Coast Guard station (5.5 m/s compared to 6.5 m/s at the Michigan City NOAA station around 1 km away).

Once these three stations are removed from the sample, the agreement between map and data improves dramatically.



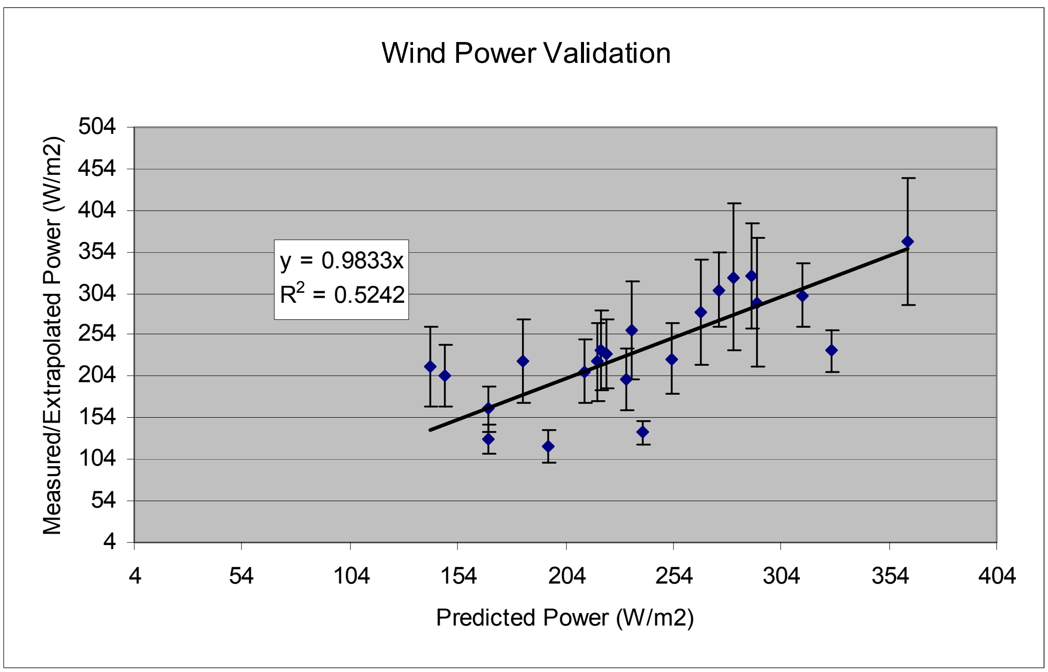


Figure 1. Scatter plots of predicted and measured wind speeds for 22 stations in Indiana at 50 m (top), and the same for wind power (bottom). The error bars reflect period of record, tower height, and anemometer sensitivity, as described in the text. The trend lines are forced through the origin.

Table 3. Revised Validation with Questionable Stations Removed

	Number of Stations	Mean Bias	RMS Discrepancy	Model Error
Speed	19	0.1 m/s (+2%)	0.4 (6.5%)	NA
Power	19	-12 W/m^2 (-5%)	32 (13%)	NA

The rms discrepancy in both power and speed is now comparable to the estimated data error margin, and the map bias is reduced to negligible levels.

After reviewing the validation results, NREL recommended moderate adjustments in speed and power in the southern part of the state. The speed adjustment ranged from a decrease of 7% in the hills around Bloomington, to an increase of 5% in the extreme southwest corner of the state near Evansville. The power was increased by about 25% around Evansville (moving this area from NREL power class 1 to class 2), and it was increased by 6% in the hills northwest of Indianapolis and east of Anderson and Muncie.

5. WIND MAPS

The accompanying maps, which incorporate the adjustments described in the previous section, show the predicted mean annual wind speed in Indiana at heights of 30, 50, 70, and 100 m; a map of mean annual wind power at 50 m is also provided.

The wind maps show that the best wind resource in Indiana is found in the north-central part of the state, and in particular, in the triangular region of higher ground between Indianapolis, Kokomo, and Lafayette, as well as to the northwest of Lafayette in Benton and White counties. In these areas the mean wind speed at 50 m height is predicted to be 6.5 to 7 m/s, and the mean wind power 250 to 350 W/m^2, or NREL class 2 to 3. There are spots of similar level of resource in northeastern Indiana (east of Elkhart in Lagrange County), as well as in Randolph County near the Ohio border. In the rest of northern Indiana, the wind speed tends to be roughly 0.5 m/s lower and the wind power is class 2.

South of Indianapolis, the wind resource declines. The predicted wind speed ranges from 4.5 to 6 m/s and the wind power class from 1 to 2. The main reason for the lower resource compared to the northern half of the state is the land cover: southern Indiana is much more forested than northern Indiana. Trees exert friction on the lower atmosphere that reduces the wind speed. A similar effect occurs in extreme northern Indiana, where land cover data indicate there are somewhat more trees and settled areas compared to the primarily agricultural land of central-northern Indiana.

Topography also plays a role. All other things being equal, hilltops usually have a better resource than valleys and plains, and the most elevated areas of Indiana are in the central and northeastern parts of the state. However, a close comparison of the topography with the predicted wind resource reveals that the model predicts surprisingly good winds on some north- and east-facing slopes, rather than only on the peaks. This pattern may be caused either by gradients in air density, which results in an gravity-induced acceleration down the slope; or by the tendency of thermally stable air to flow around high ground rather than over it. Thus, for example, the windy area of Randolph County in eastern Indiana extends somewhat down the northern slope of the hills (the highest elevation in Indiana).

The track of the jet stream also plays a part. Upper-air winds are generally stronger in northern Indiana than in the southern part of the state.

It should be stressed that the mean wind speed at any particular location may depart substantially from the predicted values, especially where the elevation, exposure, or surface roughness differs from that assumed by the model, or where the model scale is inadequate to resolve significant features of the terrain. Despite the adjustments, there is no guarantee that the revised wind map is any more accurate, especially in areas where no data was available, than the original map.

6. GUIDELINES FOR USE OF THE MAPS

The following are guidelines for interpreting and adjusting the wind speed estimates in the maps, to be used in conjunction with the accompanying ArcReader CD. The ArcReader CD allows users to obtain the "exact" wind speed value at any point, and it provides the elevation and surface roughness data used by the model, which are needed to apply the adjustment formulas given below.

1. The maps assume that all locations are free of obstacles that could disrupt or impede the wind flow. "Obstacle" does not apply to trees if they are common to the landscape, since their effects are already accounted for in the predicted speed. However, a large outcropping of rock or a house would pose an obstacle, as would a nearby shelterbelt of trees or a building in an otherwise open landscape. As a rule of thumb, the effect of such obstacles extends to a height of about twice the obstacle height and to a distance downwind of 10-20 times the obstacle height.
2. Generally speaking, points that lie above the average elevation within a 400×400 m grid cell will be somewhat windier than points that lie below it. A rule of thumb is that every 100 m increase in elevation will raise the mean speed by about 0.5 m/s. This formula is most applicable to small, isolated hills or ridges in flat terrain.
3. The mean wind speed at a location could be affected by the roughness of the land surface – determined mainly by vegetation cover and buildings – up to several kilometers away. If the roughness is much lower than that assumed by the model, the mean wind speed could be higher. Typical values of roughness range from 0.01 m in open, flat ground without significant trees or shrubs, to 0.1 m in land with few trees but some smaller shrubs, to 1 m or more for areas with many trees. These values are only indirectly related to the size of the vegetation.

   The following equation provides an approximate speed adjustment for differences in surface roughness in the direction of the wind:

$$\frac{v_2}{v_1} \approx \frac{\log\left(\dfrac{300-d}{z_{01}}\right)}{\log\left(\dfrac{h-d}{z_{01}}\right)} \times \frac{\log\left(\dfrac{h-d}{z_{02}}\right)}{\log\left(\dfrac{300-d}{z_{02}}\right)}$$

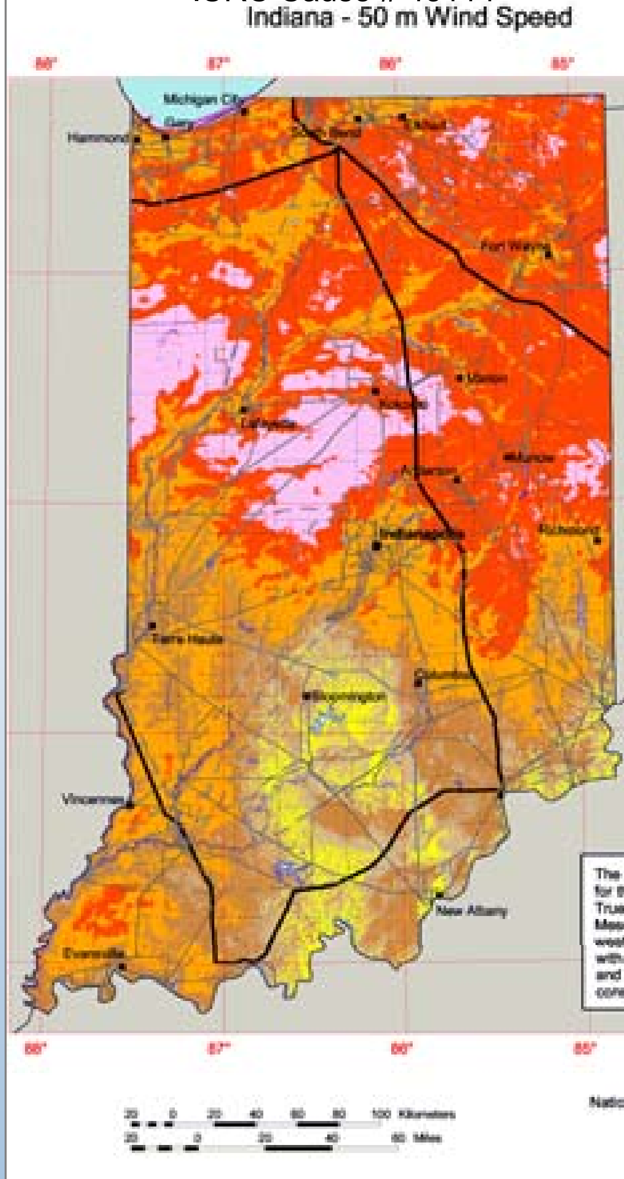
   v_1 and v_2 are the original and adjusted wind speeds at height h (in meters above ground level); z_{01} and z_{02} are the model and actual surface roughness values (in meters); and d_1 and d_2 are the corresponding displacement heights. (This equation assumes the wind is unaffected by localized roughness changes above a height of 300 m.)

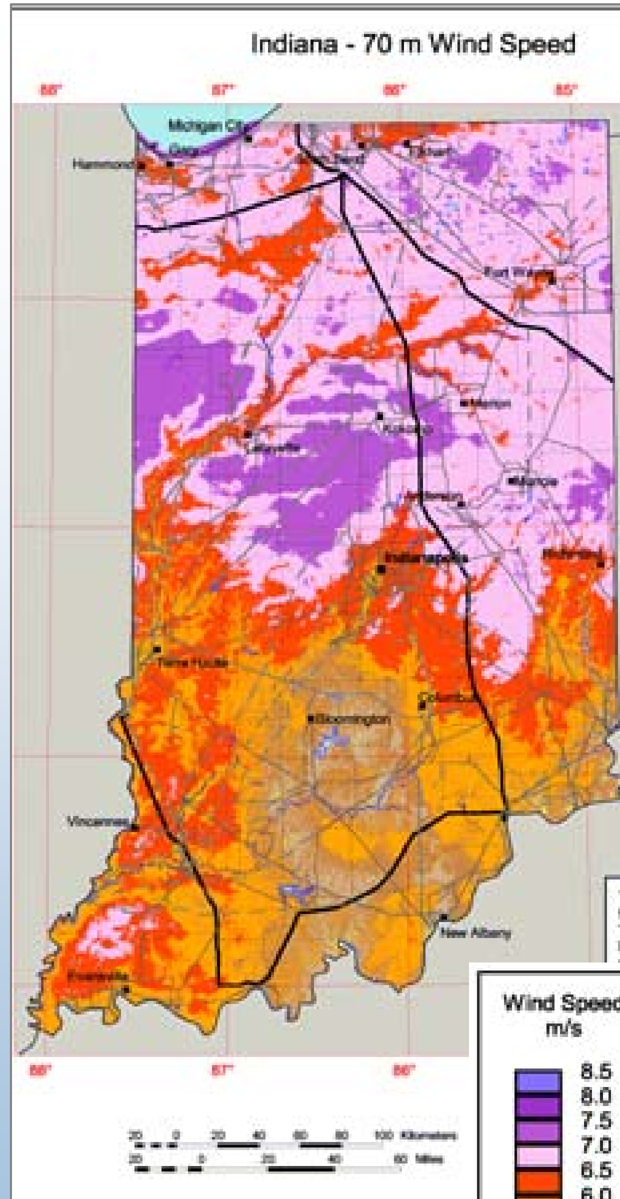
As an example, suppose the surface roughness assumed by the model was 0.2 m, and the displacement 2 m, whereas the true roughness is 0.75 m and displacement 7.5 m. For h = 50 m, the above formula gives

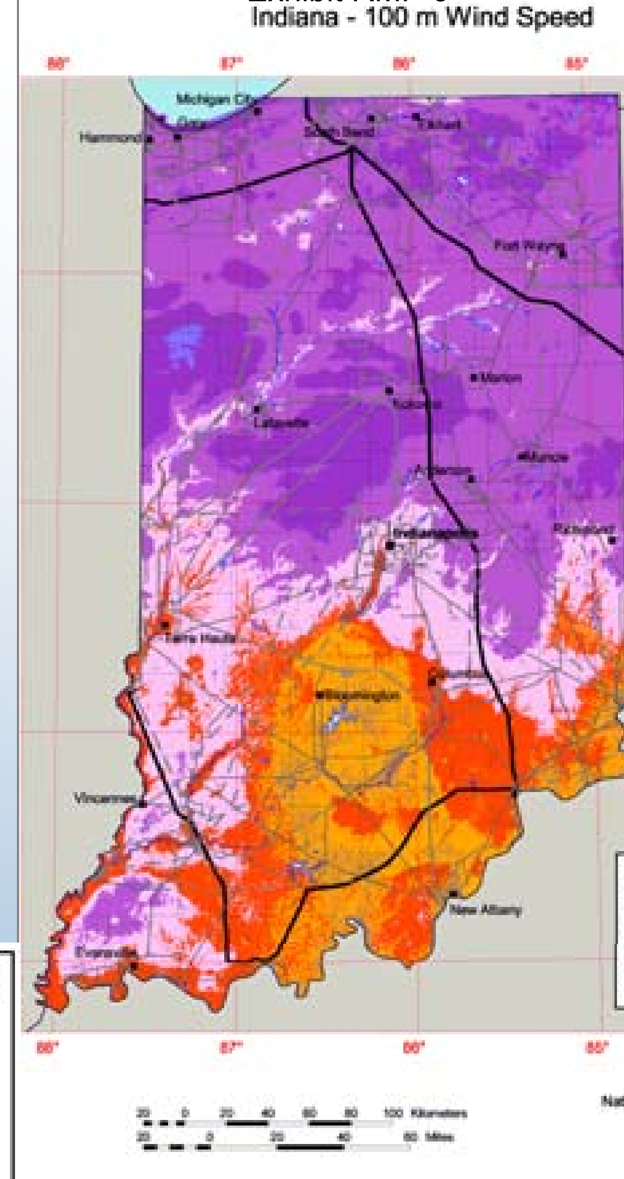
$$\frac{v_2}{v_1} \approx \frac{\log\left(\frac{300-2}{0.2}\right)}{\log\left(\frac{50-2}{0.2}\right)} \times \frac{\log\left(\frac{50-7.5}{0.75}\right)}{\log\left(\frac{300-7.5}{0.75}\right)} = 0.90$$

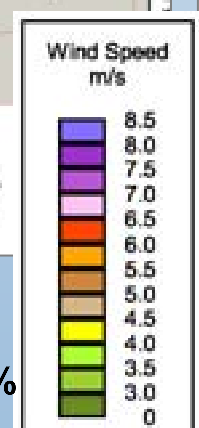
This shows that the predicted wind speed should be reduced by about 10%.

This formula assumes that the wind is in equilibrium with the new surface roughness above the height of interest (in this case 50 m). When going from high roughness to low roughness (such as from forested to open land), the clearing should be at least 1000 m wide for the benefit of the lower roughness to be fully realized. However, when going from low to high roughness, the reduction in wind speed may be felt over a much shorter distance. For this and other reasons, the formula should be applied with care.









Best areas 6.5-7 m/s
Capacity factors 30-35%

Best areas 7-7.5 m/s
Capacity factors 35-40%

Best areas 7.5-8.2 m/s
Capacity factors 40-45%

Indiana Tall Tower locations with average wind speeds (m/s) at 99-m height

One year of data (mostly 2004). These data became available after wind resource maps were produced.

Goodland's speed based on 90 m measurement
- Capacity factors* at Goodland
- 42% at 90-m height
- 32% at 50-m height

***Capacity factors for GE 1.5 MW turbine with a 77-m rotor diameter**

Source: Dennis Elliot, NREL, Presentation on Wind Resource and Wind Shear Characteristics at Elevated Heights, Wind Powering America Summit Meeting, June 8, 2006

Wind Resource and Wind Shear Characteristics at Elevated Heights

Dennis Elliott
NREL/NWTC

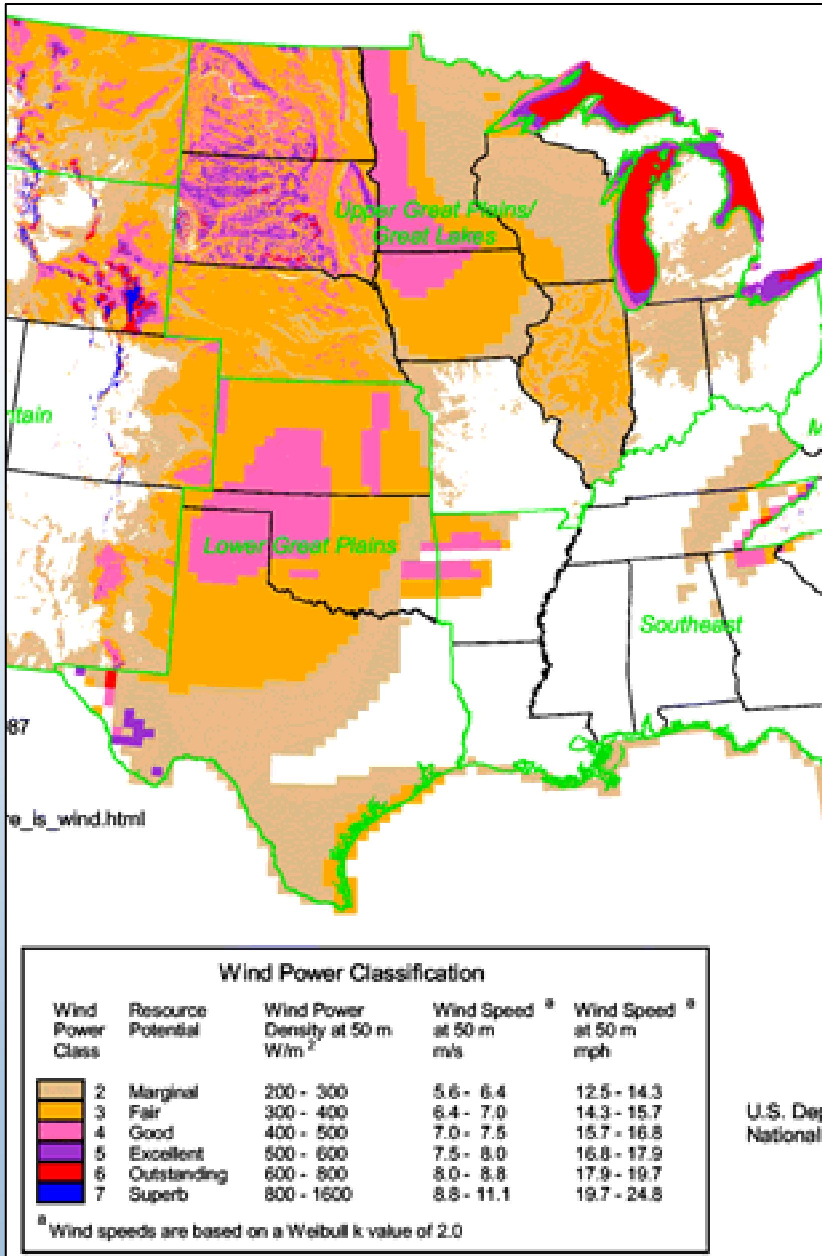
WPA Summit Meeting
June 8, 2006 Pittsburgh, PA

Objectives

- Analyze wind resource and wind shear characteristics at tall tower sites for diverse areas of the Midwest and Central Plains
  - Turbines hub heights are now 70-100 m above ground
  - Wind measurements at 70-100+ m have been rare
- Show case studies and comparisons for some areas of the Midwest (Indiana) and Central Plains (Kansas)
- Present conclusions about wind resource and shear characteristics for prime wind energy development regions

Background

- Tall tower measurements on existing communication towers established during past 5 years supported by:
  - U.S. DOE State Energy Program and Wind Powering America
  - State/university initiatives
  - Other research programs
- NREL obtains time series data from a variety of sources
- Primary areas of investigation to date
  - Central Plains (Windpower 2006 paper by Schwartz and Elliott)
    - 13 tall towers were used in the study, 11 tall towers had highest anemometer at 100-110 m, Kansas had 6 towers
  - Indiana (special study for RPS meeting on Indiana wind resources)
    - High-resolution wind maps by AWS Truewind at 70 m and 100 m
    - 5 tall towers with highest anemometers at 90-100 m

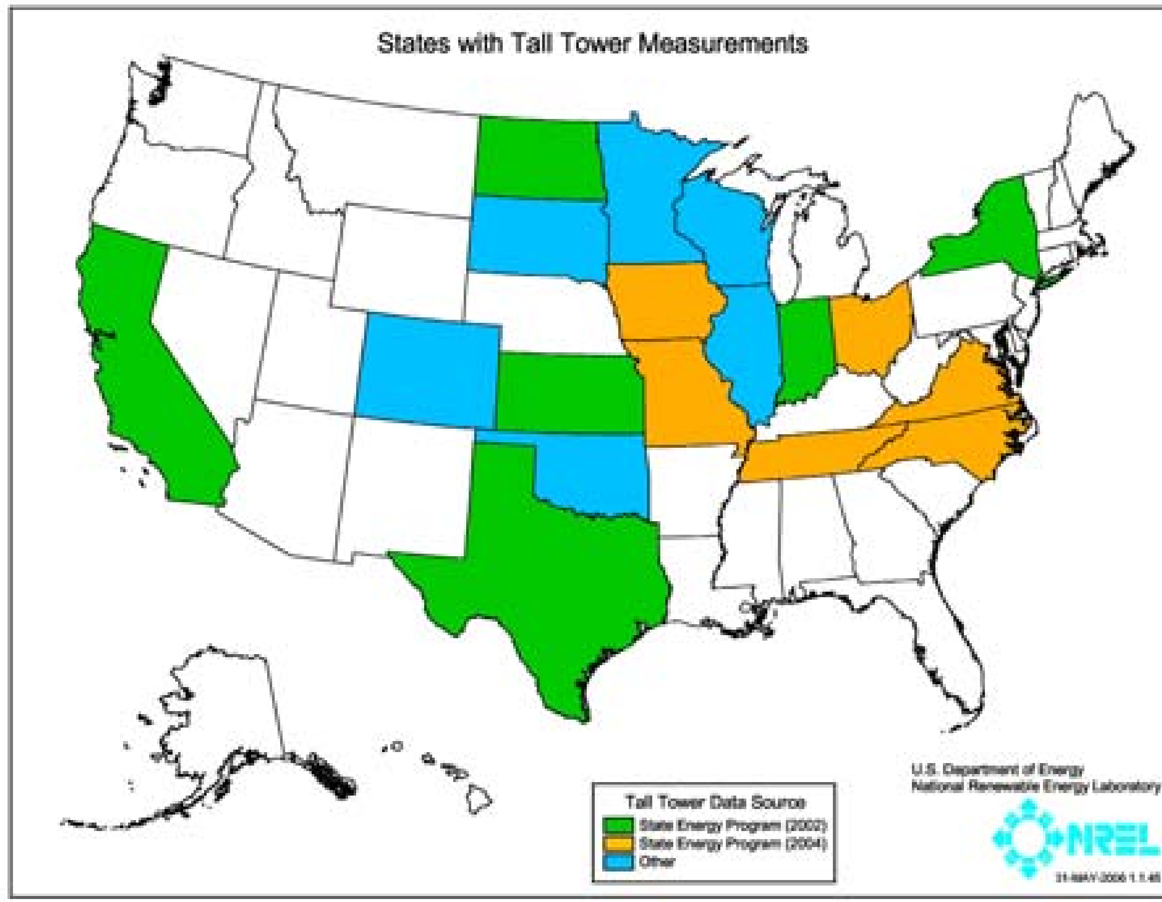


50-m Wind Power Map for Central U.S.

- Considerable uncertainty exists in extrapolating 50-m wind resource to heights of 80-100 m
- Available wind maps for heights of 80-100 m are unvalidated
- Tall-tower wind measurement data needed to examine the wind shear and make more accurate estimates at elevated heights

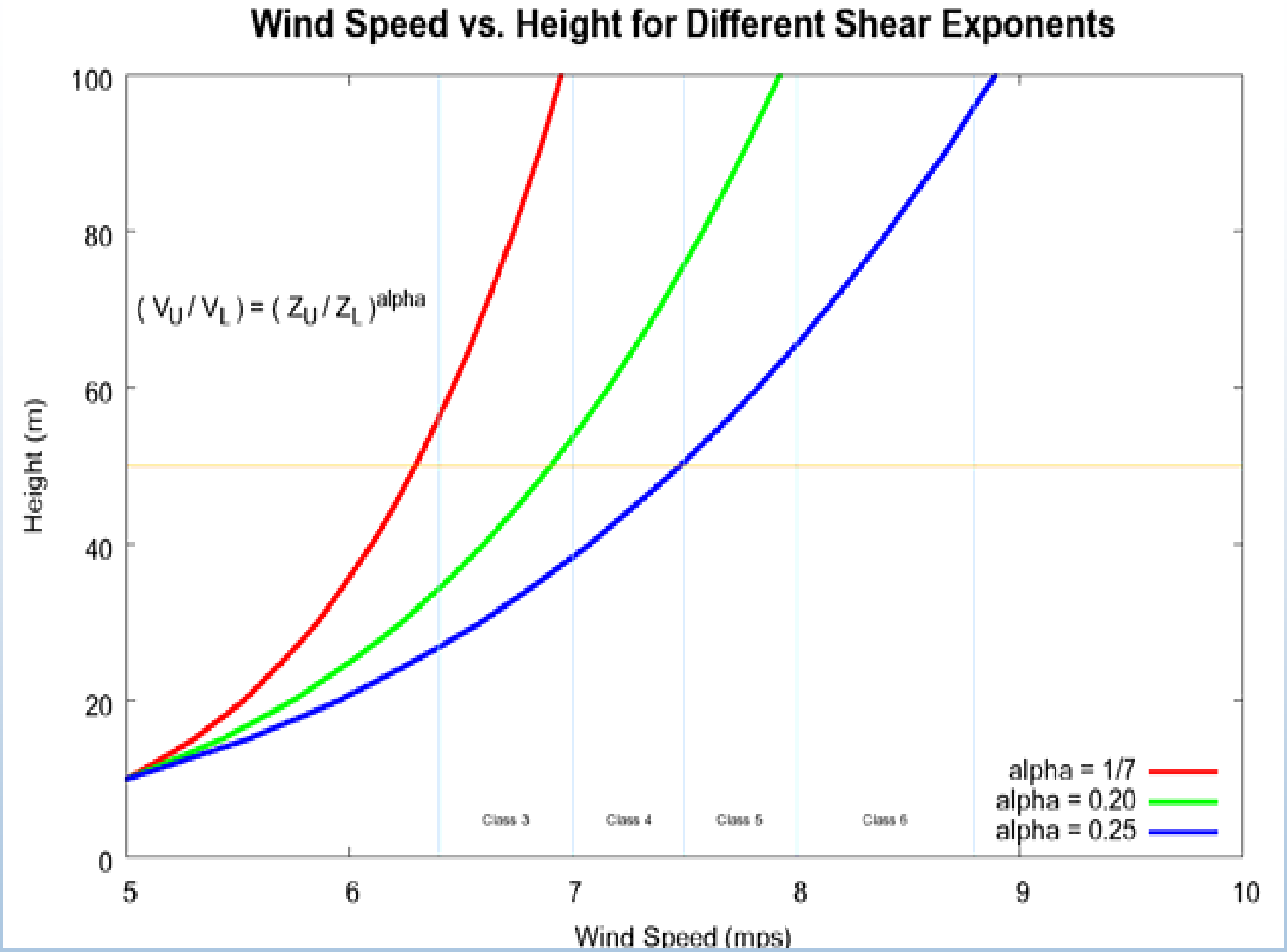
Current Tall Tower Measurements

- DOE State Energy Program (SEP) 2002 and 2004
  - 12 states
  - 35-40 towers
  - NREL provides technical support
- Other Tall-Tower Data
  - At least 6 states

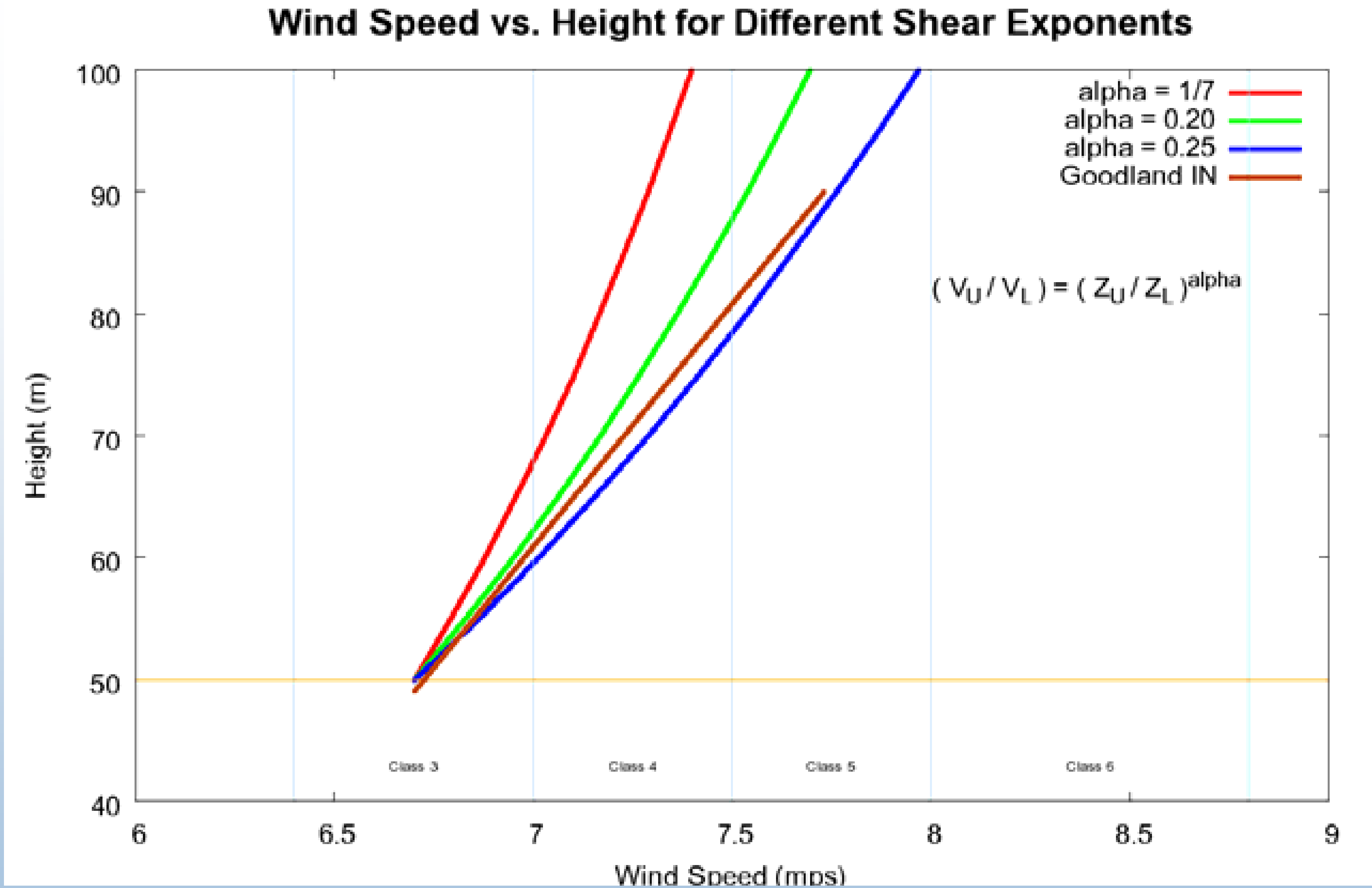


Tall Tower site on the Great Plains.

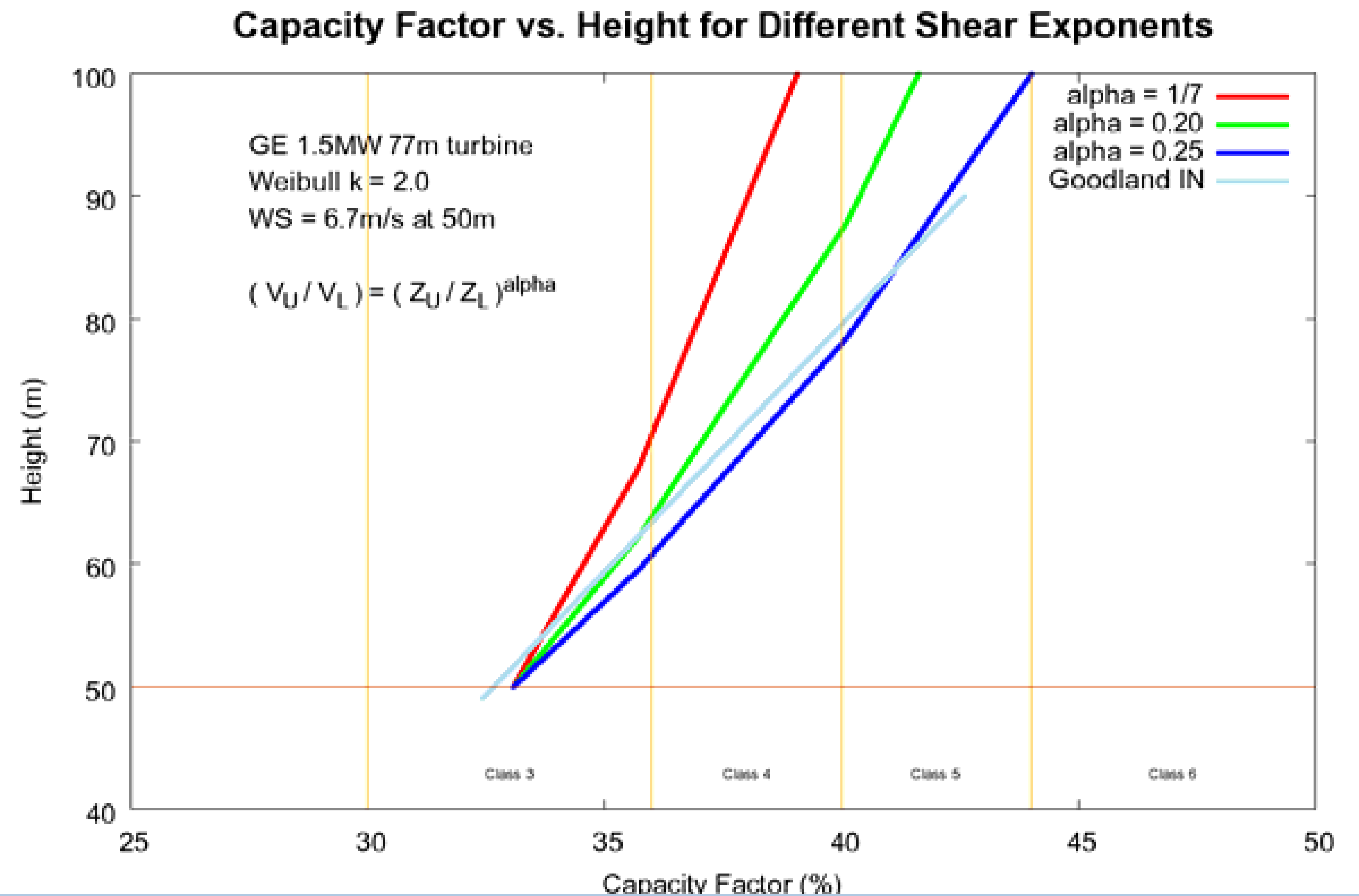
Communication towers are frequently used for measuring wind energy characteristics at heights up to 100 m or above.



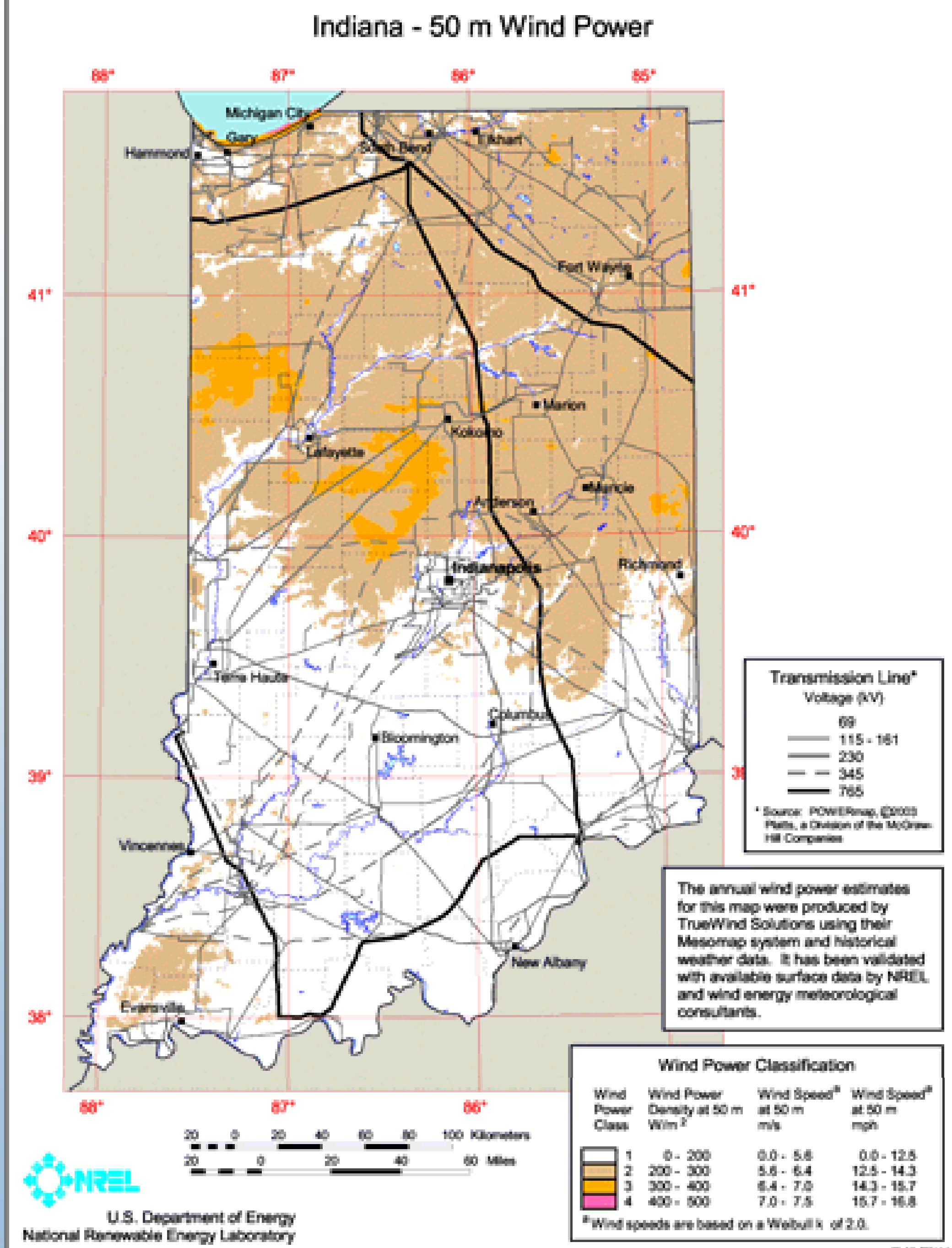
Annual average shear exponents can vary from 1/7 to 0.25, causing considerable uncertainty in vertical extrapolations of wind resource



- Even if 50-m wind resource is known, potential variations in shear exponents cause considerable uncertainty in wind resource at heights of 80-100 m
- Measured shear exponent at Goodland is 0.235, with much higher wind resource at 90 m than estimated by 1/7 shear estimate



- High wind shear locations can have considerably higher capacity factors at 80-100 m than low shear locations, given similar capacity factors at 50 m
- Goodland's capacity factor of 42.5% at 90 m is considerably higher than would be estimated by using typical shears of 1/7 to 0.2



Indiana Wind Power Map – 50 m Height

- This is the standard wind map product posted on WPA web site
- AWS Truewind used numerical modeling to produce initial wind map estimates
- NREL and consultants used available measurement data to validate the initial estimates
- This final map (produced in 2004) includes the revisions from validation
- Additional map products were produced for heights of 70m and 100m but not validated
- Tall-tower wind measurement program (5 sites) began in 2004

Indiana Tall Tower locations with average wind speeds (m/s) at 99-m height

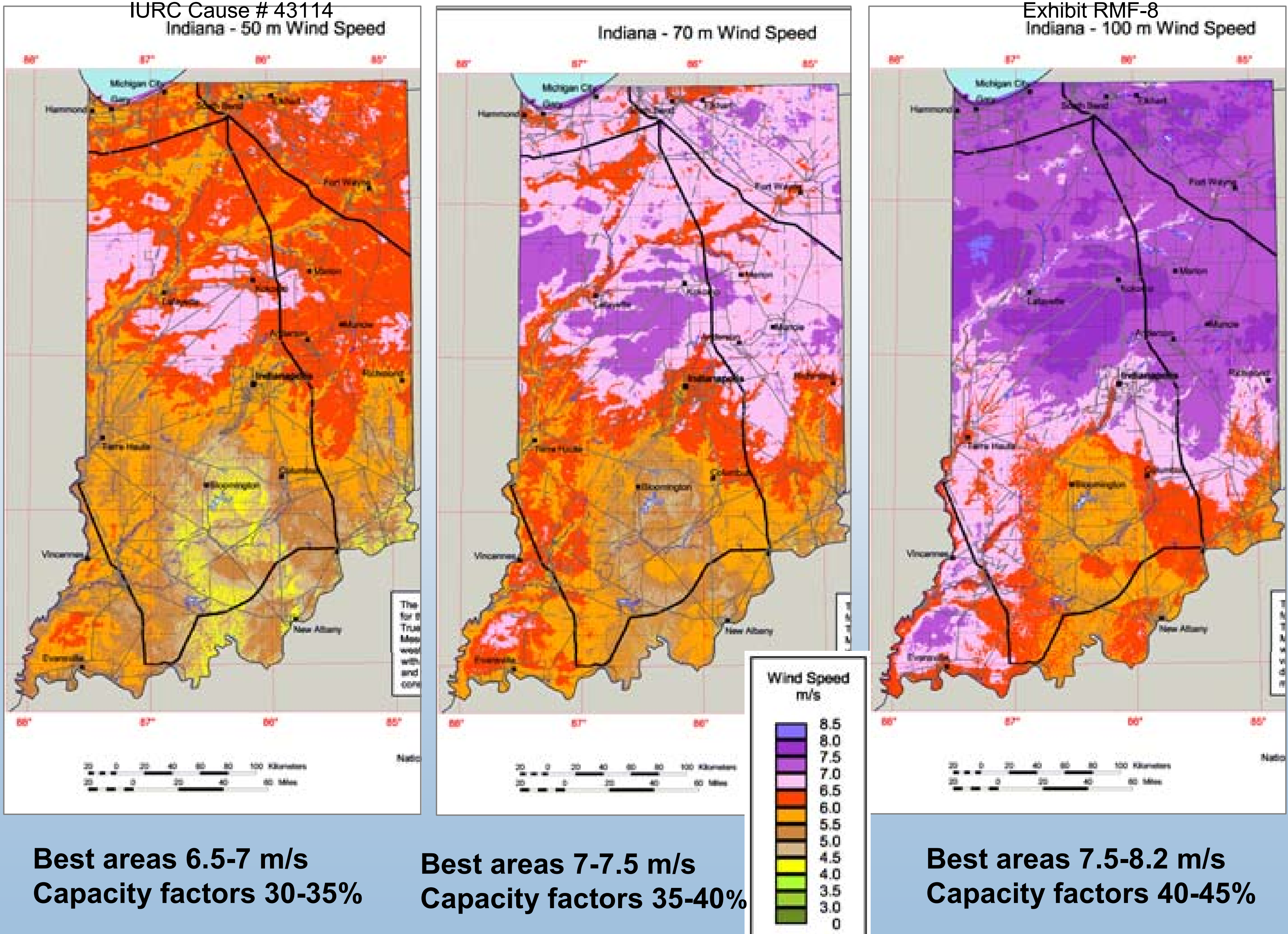
One year of data (mostly 2004). These data became available after wind resource maps were produced.

Goodland's speed based on 90 m measurement
- Capacity factors* at Goodland
- 42% at 90-m height
- 32% at 50-m height

***Capacity factors for GE 1.5 MW turbine with a 77-m rotor diameter**

IURC Cause # 43114

Exhibit RMF-8



Best areas 6.5-7 m/s
Capacity factors 30-35%

Best areas 7-7.5 m/s
Capacity factors 35-40%

Best areas 7.5-8.2 m/s
Capacity factors 40-45%

Methodology for Estimating Indiana's Wind Electric Potential at 70-m and 100-m Heights

We calculated a range of wind speeds and capacity factors for Indiana wind resources at 70-m and 100-m heights. The wind speed ranges (after 12% power losses) were used to estimate the windy land area and wind potential at map heights of 70m and 100m.

Wind potential was estimated assuming 5 MW of installed wind capacity per square kilometer of available windy land, after environmental and land-use exclusions. Capacity factors were based on the GE 1.5 MW 77-m turbine. If the assumed power losses increase, the wind speeds must also increase to maintain the same capacity factor.

No Power Losses			12% Power Losses	
50-m Class (equivalent)	Speed m/s	Capacity Factor (%)	Speed m/s	50-m Class (equivalent)
Class 3	6.5 – 7.1	30 – 36	7.0 – 7.6	Class 4
Class 4	7.1 – 7.7	36 – 42	7.6 – 8.3	Class 5
Class 5	7.7 – 8.3	42 – 46	Not applicable	

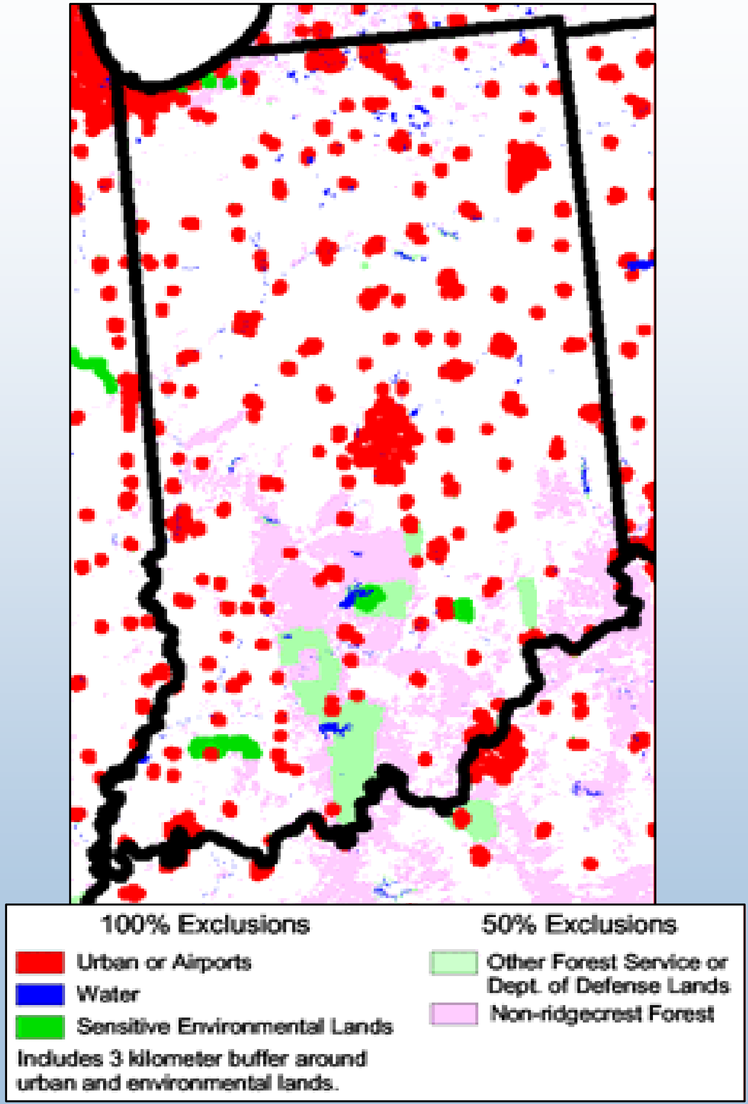
Estimates of Indiana's Wind Electric Potential (Installed Capacity)

Assumes **12% Power Losses**

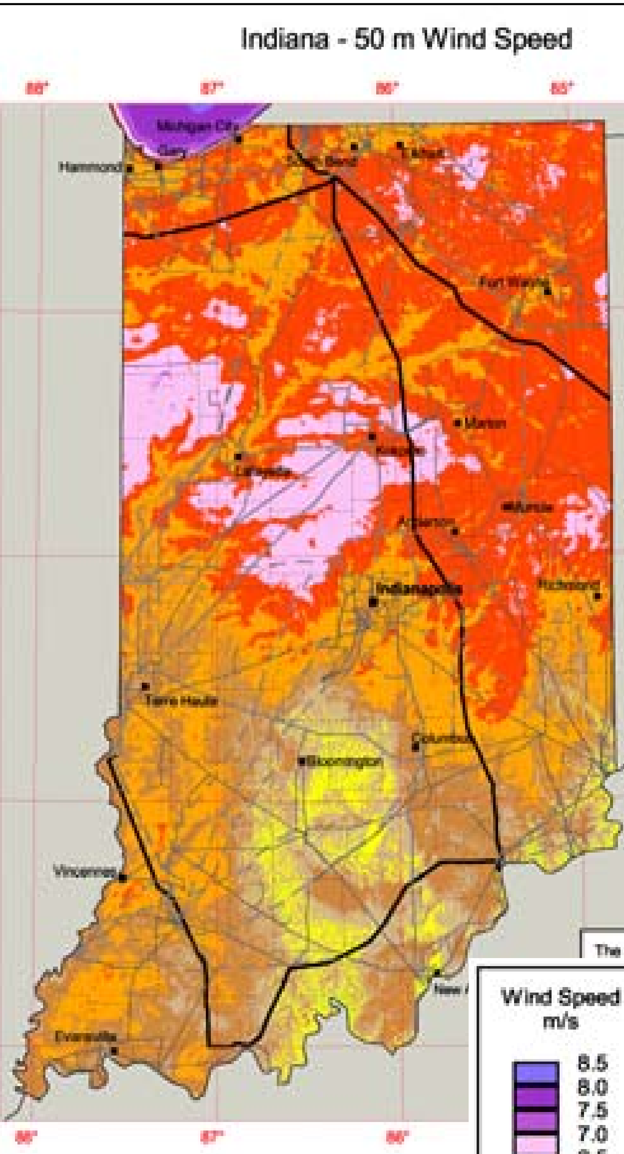
	70-m Height	**100-m Height**
Class 4	42 GW	161 GW
Class 5	0 GW	37 GW
Total	**42 GW**	**198 GW**

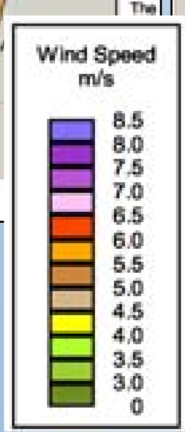
Areas Excluded from Developable Wind Potential

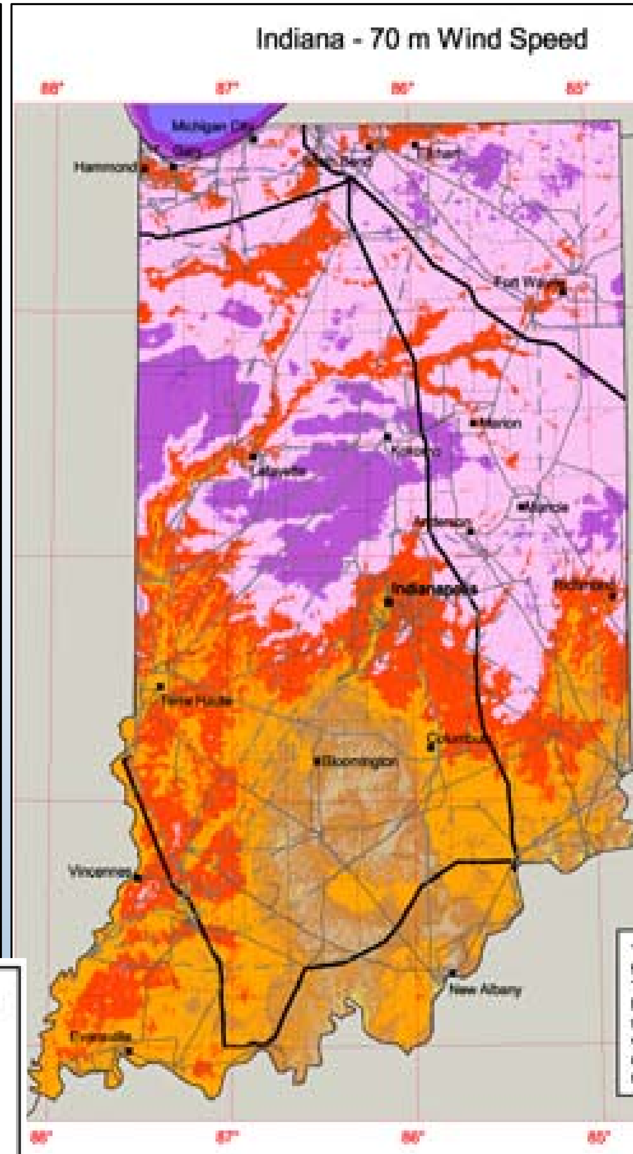
1) Potentially sensitive environmental lands:
   - National Park Service and Fish and Wildlife Service
   - Wildlife, wilderness, recreation areas, and other specially designated areas on federal land (predominantly Forest Service and BLM lands)
   - Some state and private environmental lands where data was available
   - Half of the remaining U.S. Forest Service and Department of Defense lands to represent current dedicated use of land
2) Potentially incompatible land use:
   - Urban areas, airports, wetlands and water bodies
   - Half of non-ridge crest forested areas
3) Other factors:
   - Slopes greater than 20%
   - A 3 kilometer area surrounding environmental and land use excluded areas (except water bodies)
   - Small, isolated class 3 and greater resource areas using a minimum density criteria

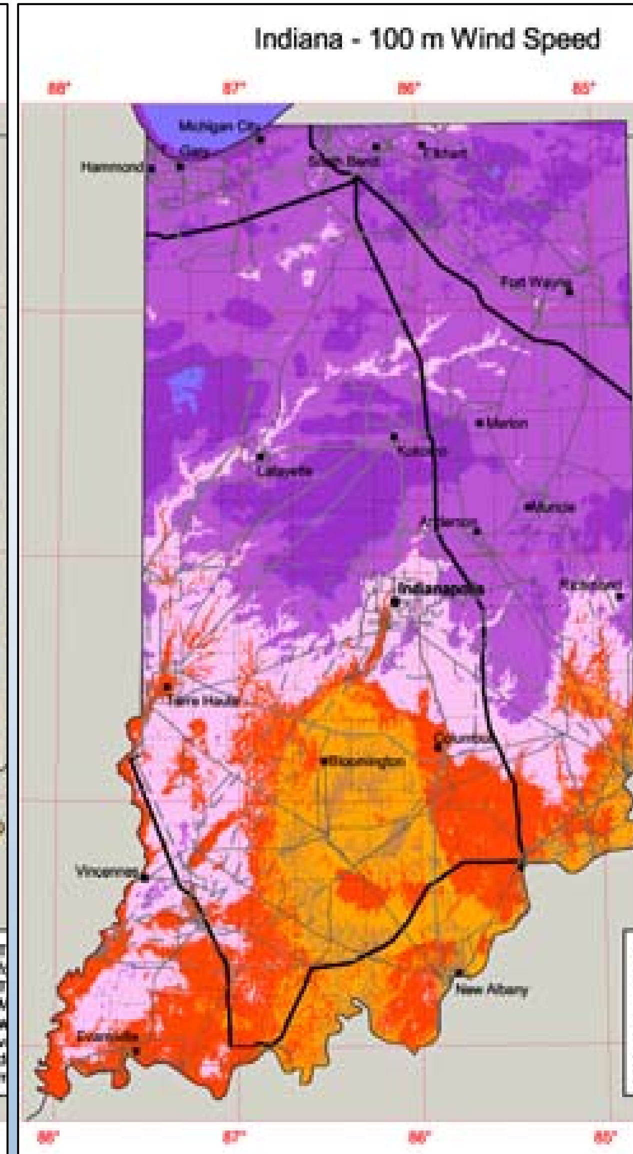


11% of the raw Class 3 and better lands excluded at 70 m (12% loss case)
19% of the raw Class 3 and better lands excluded at 100 m (12% loss case)









Wind Potential (Installed Capacity) for
12% Power Loss Scenario
30-36% Capacity Factor: 42 GW

Total: 42 GW

Wind Potential (Installed Capacity) for
12% Power Loss Scenario
30-36% Capacity Factor: 161 GW
36-41% Capacity Factor: 37 GW
Total: 198 GW

Wind Shear Characteristics Analyzed From Tall Tower Data in Plains and Midwest

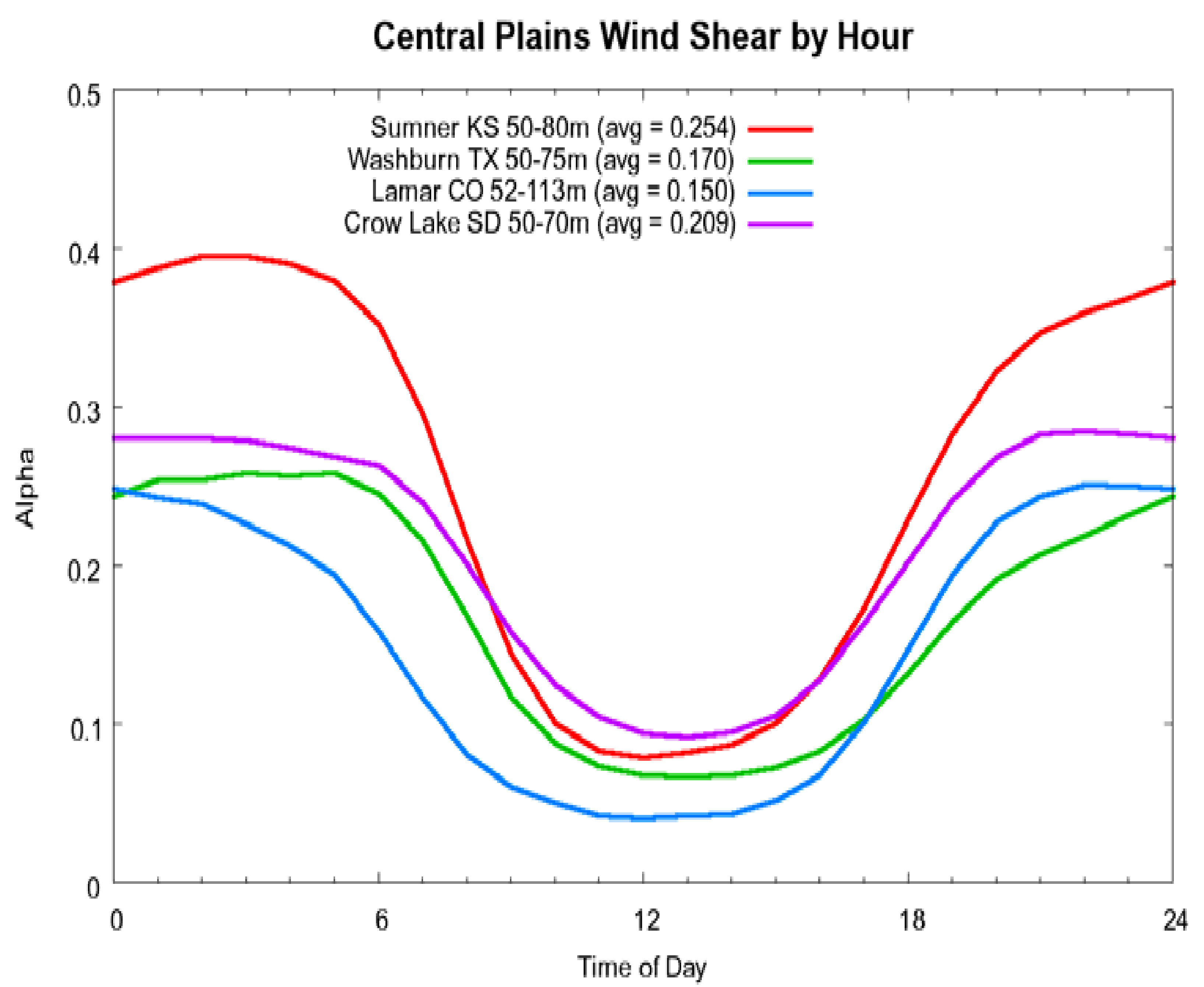
- Annual average
- Diurnal variability
- Seasonal variability
- Shear variation by prevailing wind directions
- Investigate wind shear variation by height
- Variations within and among geographic regions

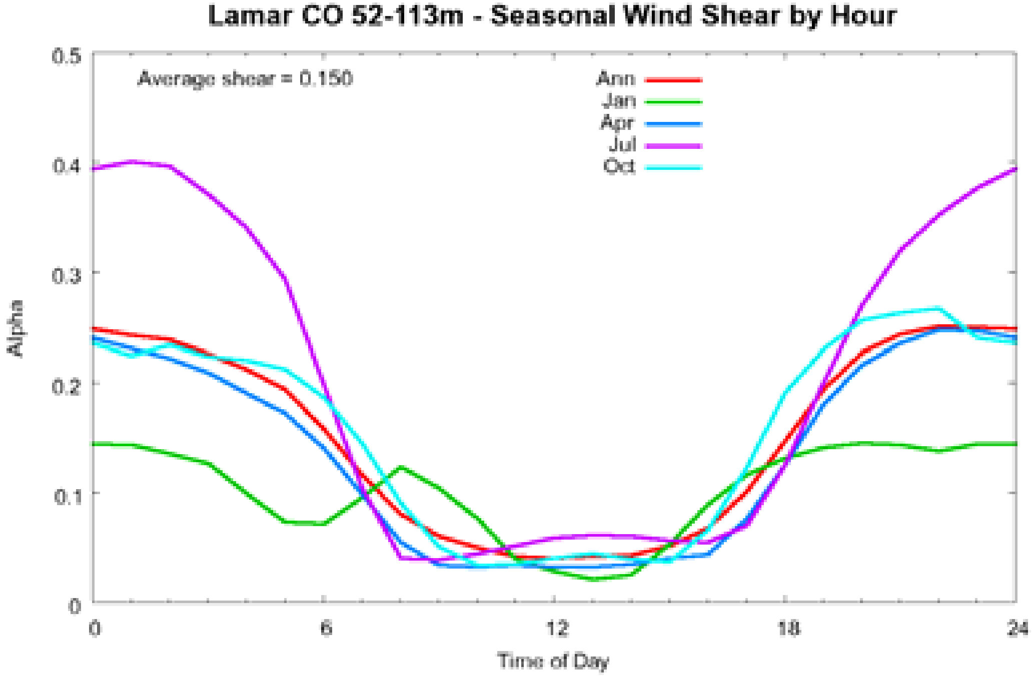
Central Plains Tall Tower Locations

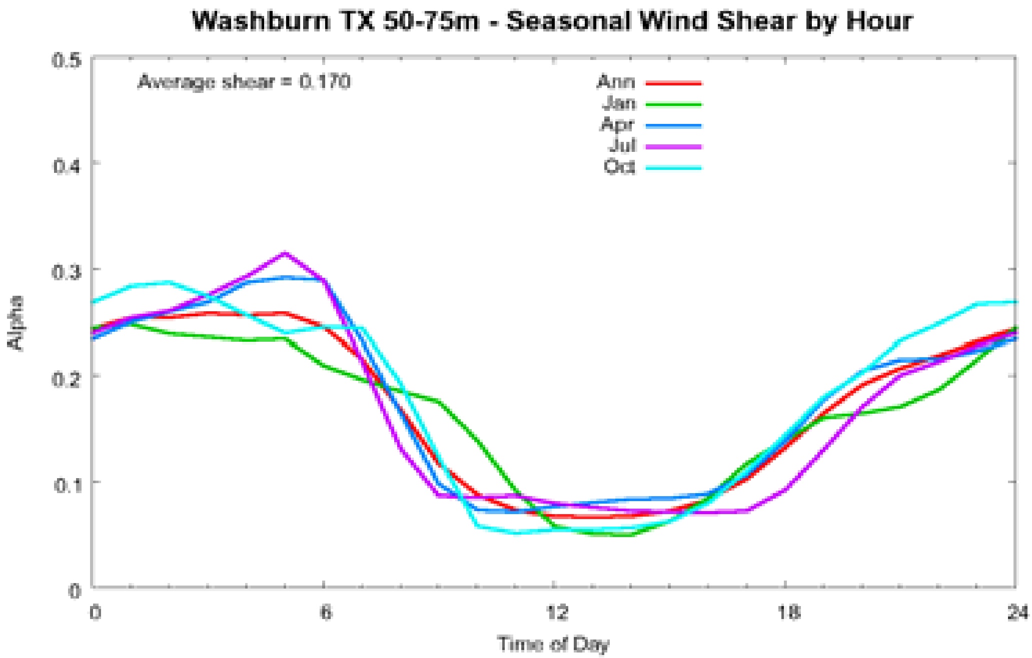
Central Plains Tall Tower Shear Values

Shear Climate Summary

- Annual average shear between 0.15 and 0.25
- Greater variation of annual wind shear between towers within a region than between the southern and northern Plains and the Midwest
- Diurnal shear pattern similar throughout region
  - Daytime shear is 0.05-0.1
  - Nighttime shear between 0.25-0.40
  - Some seasonal variations among towers
- Winds from south had higher shear than winds from north
  - South winds shear 0.2-0.3
  - North winds shear 0.1-0.2


Central Plains Wind Shear by Hour
Sumner KS 50-80m (avg = 0.254)
Washburn TX 50-75m (avg = 0.170)
Lamar CO 52-113m (avg = 0.150)
Crow Lake SD 50-70m (avg = 0.209)
Alpha
0.5
0.4
0.3
0.2
0.1
0
0
6
12
18
24
Time of Day

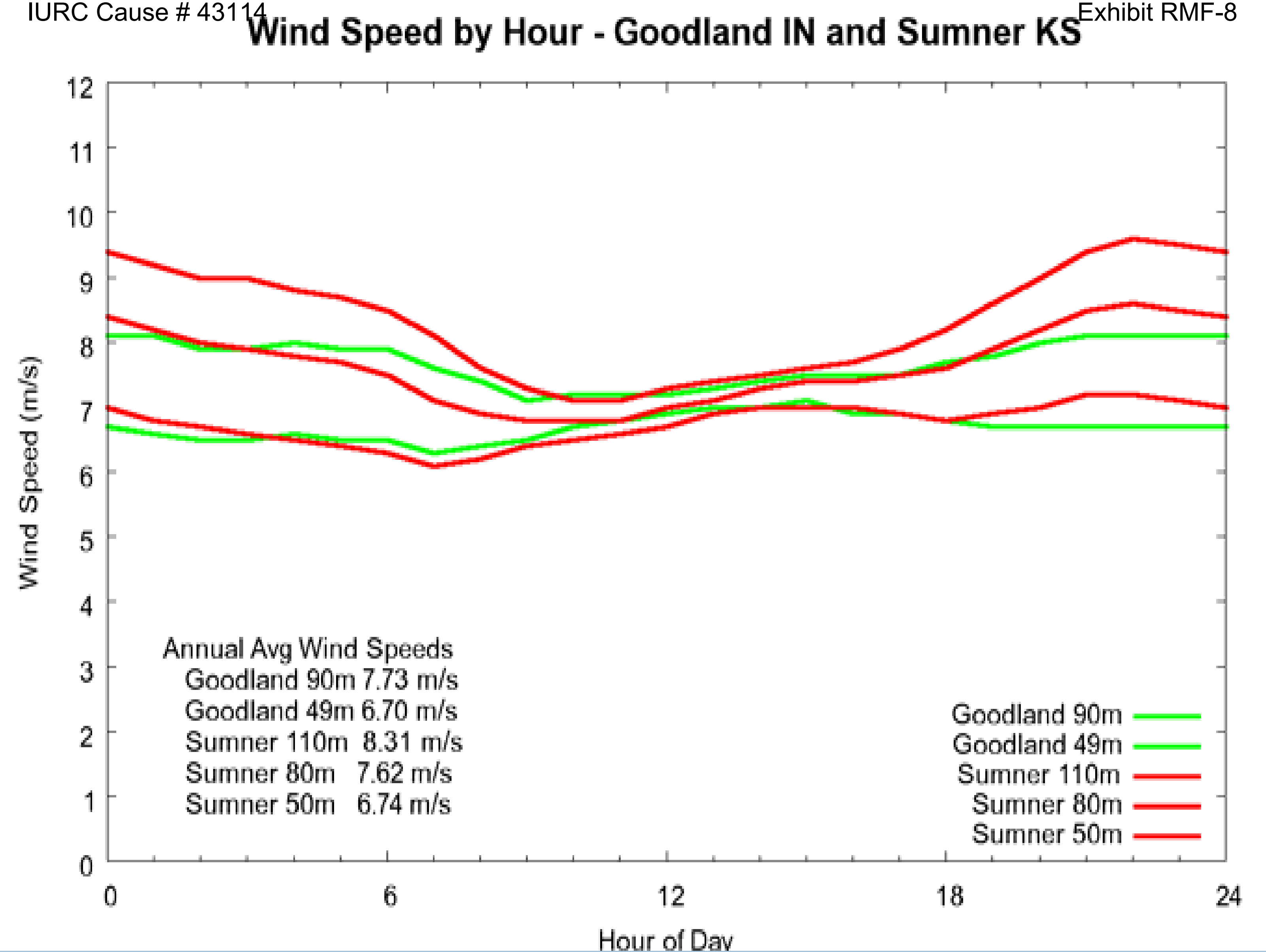




Seasonal and Diurnal Wind Shear

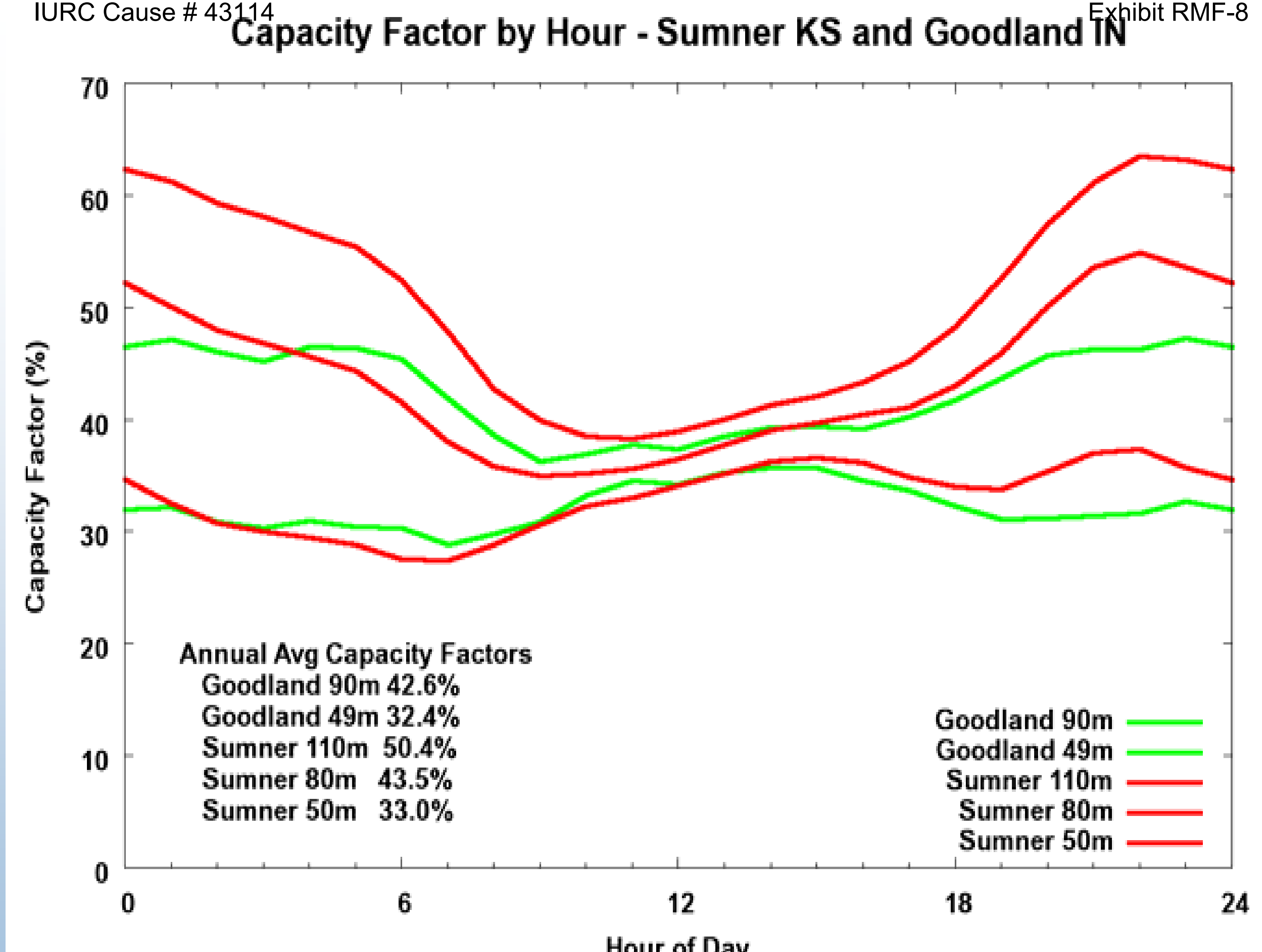
- Lamar CO has much larger nocturnal shears in summer than in winter

- Washburn TX has similar nocturnal shears across the seasons

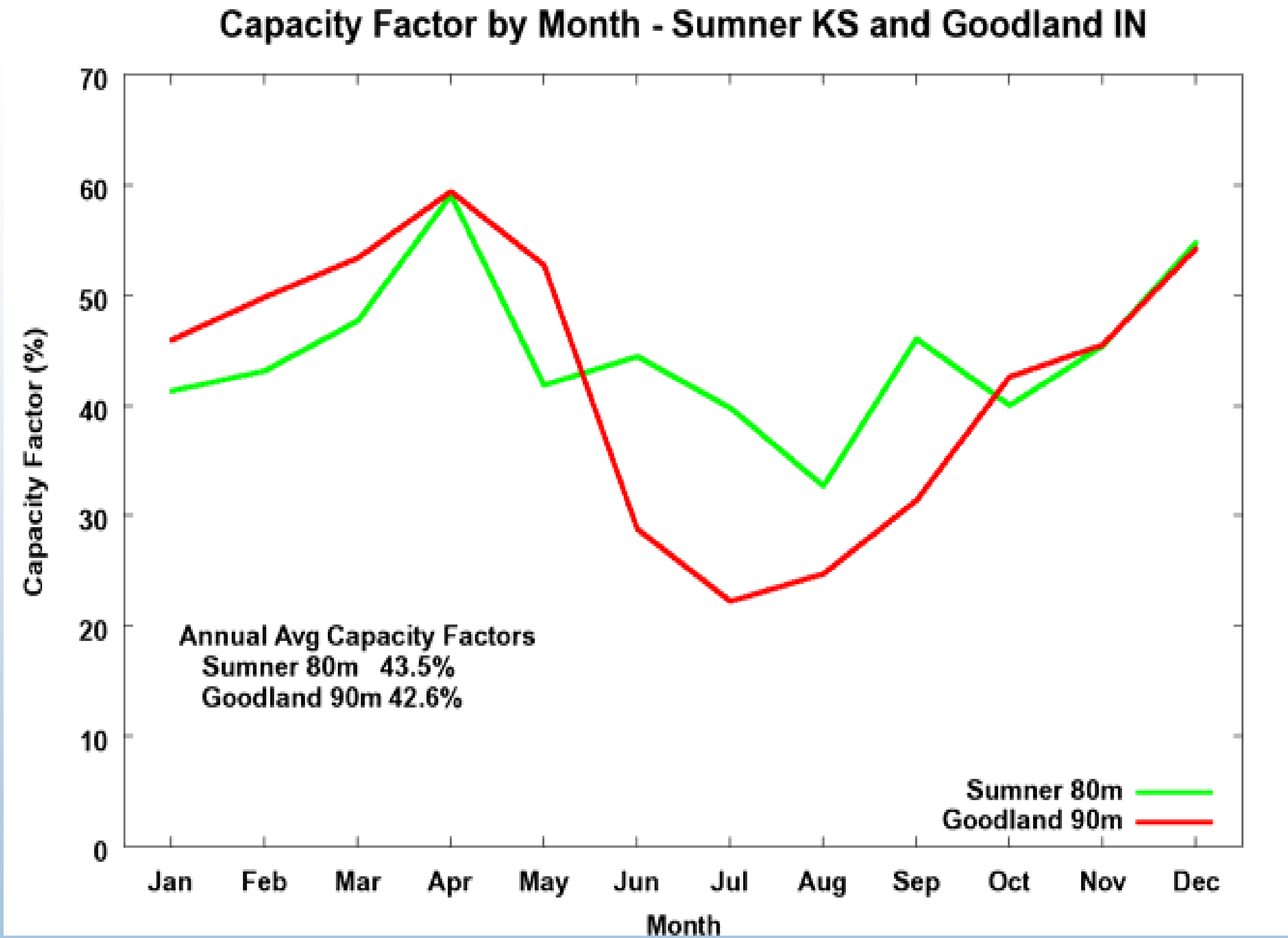


Goodland IN and Sumner KS have similar wind resource and wind shear

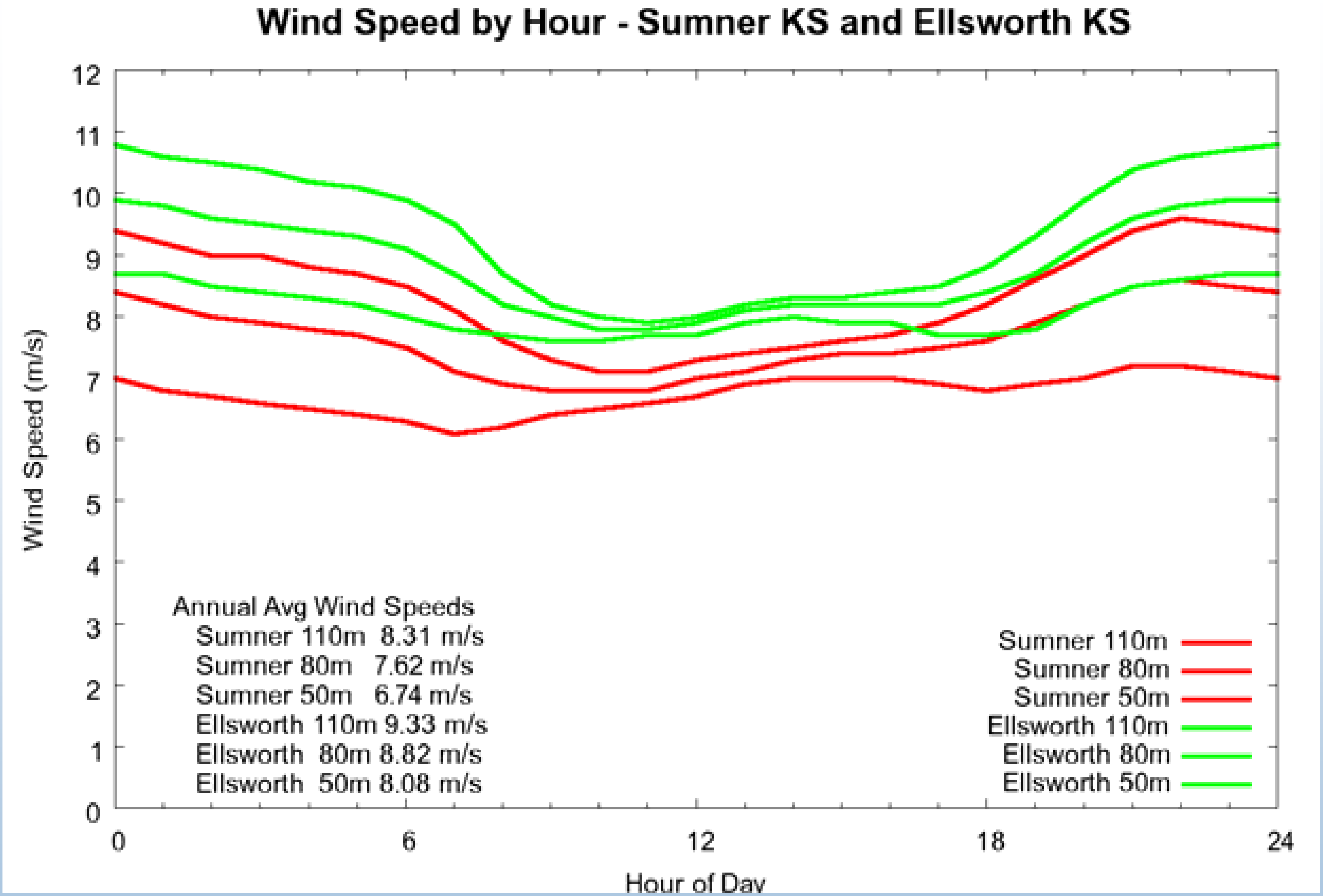
NREL National Renewable Energy Laboratory



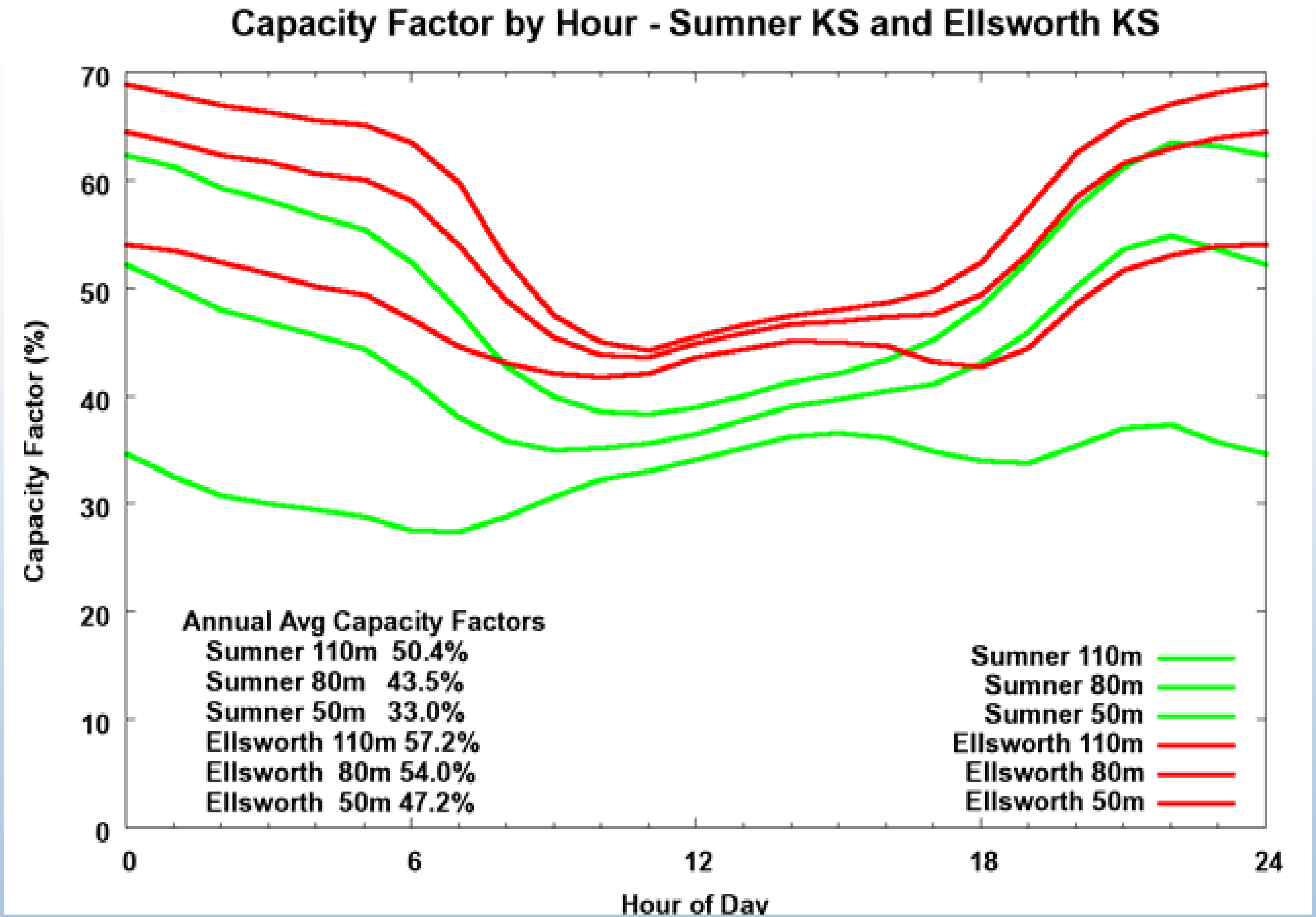
Goodland IN and Sumner KS have similar capacity factors and both locations have large increases in capacity factors between 50 m and 80-90 m heights



Goodland IN has larger seasonal variations than Sumner KS in capacity factors at 80-90 m



- **Comparison of wind resources at two locations in central Kansas**
- **At 50m, Sumner is Class 3 and Ellsworth is Class 4-5**
- **Wind shear is greater at Sumner than Ellsworth, and speed differences decrease with increased height**



- Comparison of capacity factors at two locations in central Kansas
- Capacity factors increase more rapidly with height at Sumner than at Ellsworth
- Difference in capacity factors halved at 80-110 m compared to 50 m

Conclusions

- Tall-tower data from Midwest and Plains regions indicate many locations can have high annual average wind shear (0.2-0.25) at heights between 50-100 m
  - At these locations, Class 3 sites at 50 m can have Class 4-5 equivalent wind resource at 80-100 m heights and gross capacity factors exceeding 40%
- Variations of annual wind shear within a region can be greater than variations among different regions
  - Within a region, less energetic wind resource locations at 50 m tend to have greater wind shear than more energetic locations
- Additional tall-tower data are needed to characterize the wind resource and wind shear in wind energy development regions

Final Report - 2006 Minnesota Wind Integration Study
Volume I

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PREFACE

In May of 2005 the Minnesota Legislature adopted a requirement for a Wind Integration Study of the impacts on reliability and costs associated with increasing wind capacity to 20% of Minnesota retail electric energy sales by the year 2020, and to identify and develop options for utilities to use to manage the intermittent nature of wind resources[1]. The law authorizes and directs the Reliability Administrator to manage the study. In July of 2005 the Minnesota Public Utilities Commission ordered[2]: 1) All Minnesota electric utilities to participate in the study; 2) The Minnesota electric utilities to contract jointly with an independent firm to conduct the study and to cooperate with completion of the study; and 3) The Minnesota electric utilities to use the study results to estimate impacts on their electric rates of increasing wind capacity to 20 percent and incorporate the study's findings in resource plans and renewable energy objectives reports.

In the summer of 2005, a thorough and complete review of the current status and understanding of integrating wind power into electric power systems was completed. In September 2005, a broad stakeholder group was convened to develop the detailed study scope. This group included representatives of the Minnesota electric utilities, renewable energy advocates, community-based energy development, the Minnesota legislature, the Minnesota Department of Commerce, MISO, MAPP, and national technical experts. The resulting study scope focused on characterization of the Minnesota wind resource and quantifying reliability and operating impacts resulting from significant increases in wind generation.

The objectives of the study are to:

1. Evaluate the impacts on reliability and costs associated with increasing wind capacity to 15%, 20%, and 25% of Minnesota retail electric energy sales by 2020;
2. Identify and develop options to manage the impacts of the wind resources;
3. Build upon prior wind integration studies and related technical work;
4. Coordinate with recent and current regional power system study work;
5. Produce meaningful, broadly supported results through a technically rigorous, inclusive study process.

The study was competitively bid. The Reliability Administrator selected a study team led by EnerNex Corporation, an electric power engineering and consulting firm. WindLogics was responsible for characterization of the wind resource and the detailed wind plant output modeling. The Midwest Independent System Operator (MISO) has been a key study participant supplying power system data and models, contributing technical expertise, and, in collaboration with the study contractor, has run much of the power system modeling.

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[1] Minnesota Laws 2005, Chapter 97, Article 2, Section 6.

[2] Order Directing Participation in and Implementation of a Wind Integration Study, July 22, 2005, Docket No. E-999/CI-05-973

The study began in December 2005 and was completed in November 2006. Both the challenging study scope and the aggressive schedule have been very significant challenges.

The study has benefited from extensive expert guidance and review by a Technical Review Committee (TRC). Four TRC meetings, each a full day, and numerous conference calls were held throughout the course of the study to review and discuss the study methods and assumptions, wind scenarios, model development, results, and conclusions. With excellent input from the utilities, MISO, wind interests, and national experts, we have reached consensus on overall study methods and assumptions, on the wind scenarios to be studied, on the modeling approach, and on the key results and conclusions. Participants in the TRC included:

Steve Beuning, Xcel Energy

Ed DeMeo, Utility Wind Integration Group

John Dunlop, American Wind Energy Association

Dave Geschwind, Southern Minnesota Municipal Power Agency

Brian Glover, Mid-Continent Area Power Pool/ Midwest Reliability Organization

Jeff Haase, MN Department of Commerce

Daryl Hanson, Otter Tail Power

Mike Jacobs, American Wind Energy Association

Paul Johnson, Minnesota Power

Brendan Kirby, Oak Ridge National Laboratory

Andrew Lucero, Minnesota Power

David Lemmons, Xcel Energy

Michael McMullen, Xcel Energy

Mike Michaud, Community-Based Energy Development

Michael Milligan, National Renewable Energy Laboratory

Dale Osborn, Midwest Independent System Operator

Brian Parsons, National Renewable Energy Laboratory

Rick Peterson, Xcel Energy

Dean Schiro, Xcel Energy

Matt Schuerger (TRC Chair), Technical Advisor to the MN PUC

John Seidel, Mid-Continent Area Power Pool / Midwest Reliability Organization

Stan Selander, Great River Energy

Charlie Smith, Utility Wind Integration Group

JoAnn Thompson, Otter Tail Power

Jerry Tielke, Missouri River Energy Services

Lise Trudeau, Minnesota Department of Commerce

Chuck Tyson, Midwest Independent System Operator

Ray Wahle, Missouri River Energy Services

Ken Wolf, Minnesota Public Utilities Commission

Zheng Zhou, Midwest Independent System Operator

Thank you to all of the study participants for an extraordinary effort and a ground breaking study.

Ken Wolf

Reliability Administrator

Minnesota Public Utilities Commission

EXECUTIVE SUMMARY

Wind generation cannot be controlled or precisely predicted. While these attributes are not unique to wind generation, variability of the fuel supply and its associated uncertainty over short time frames are more pronounced than with conventional generation technologies. Energy from wind generating facilities must be taken "as delivered", which necessitates the use of other controllable resources to keep the demand and supply of electric energy in balance.

Integrating wind energy involves the use of supply side resources to serve load not served by wind generation and to maintain the security of the bulk power supply system. Conventional resources must then be used to follow the net of wind energy delivery and electric demand and to provide essential services such as regulation and contingency reserves that ensure power system reliability. To the extent that wind generation increases the required quantity of these generating services, additional costs are incurred.

The high reliability of the electric power system is premised on having adequate supply resources to meet demand at any moment. In longer term planning, system reliability is often gauged in terms of the probability that the planned generation capacity will be sufficient to meet the projected system demand. It is recognized that 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. Even if the installed capacity in the control area exceeds the peak projected load, there is some non-zero probability that the available capacity might be insufficient to meet load in a given hour

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.

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 are the important questions.

The work reported here addresses two major questions:

1. To what extent would wind generation contribute to the electric supply capacity needs for Minnesota electric utility companies?
2. What are the costs associated with scheduling and operating conventional generating resources to accommodate the variability and uncertainty of wind generation?

APPROACH

The critical first step in answering either of these overarching questions is to determine what the wind generation would "look like" to the operators of the power system. This step is surprisingly difficult. The aggregate production from individual wind turbines spread out over thousands of square miles depends on the meteorology over the entire region as well as the influences of terrain and ground cover in the vicinity of a single turbine.

In addition, the meteorological patterns that dictate wind energy production also have an influence on electric demand. Periods of extended heat or cold significantly influence electric demand, and the meteorological patterns responsible for these conditions also effect the energy production from wind generation facilities.

The correlation between electric demand and wind generation has a significant effect on the costs associated with integrating wind energy. If the daily pattern of wind generation matched the daily load cycles, wind generation would likely have no integration cost. As previous studies and assessments have shown, however, this is not the case in most parts of the United States.

Consequently, the wind generation model used for this study is critically important. Because of this sensitivity, and the large geographic expanse in the 20% wind scenario, the latest technology for characterizing wind generation was employed in this study.

The technique used in this study to create the wind generation characteristics and profiles for analysis is based on re-simulating the weather over the Upper Great Plains for historical years. The simulation model is adapted from the atmospheric models used by the National Weather Service and other agencies for generating short-term forecasts. The advantage of considering historical years for this study lies in the fact that observations of actual conditions both inside and outside the area of interest were made and archived. In addition, we also know the patterns of electric demand.

The initial portions of this project were focused on characterizing the wind resource in Minnesota and developing chronological wind speed and wind generation forecast data for use in later analytical tasks.

Minnesota wind development scenarios were constructed to support the development of the wind generation model for the analytical tasks. The target wind penetration level is based on 15%, 20%, and 25% of projected retail electricity sales in the study year 2020.

Data at 152 grid points (proxy towers or wind plants, nominally 40 MW each) were calculated every 5 min as the simulation progressed through historical years 2003, 2004, and 2005. This process ensured that the character and variability of the wind resource over several time scales across geographically dispersed locations is captured.

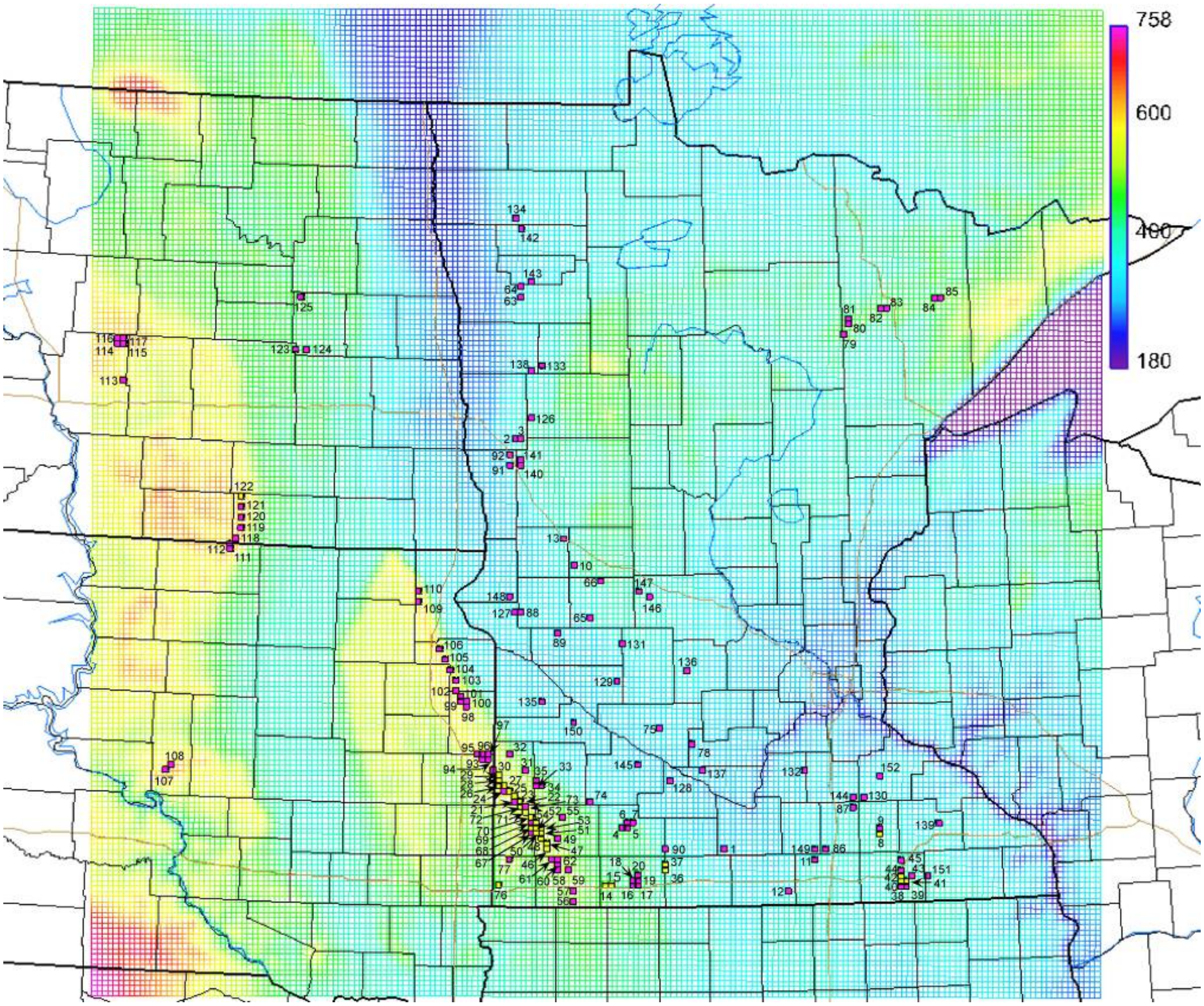


Figure 1: Location of "proxy towers" (model data extraction points) on inner grid.

Data from the meteorological simulations was used to construct a detailed picture of the wind resource in the region. Findings from this analysis are documented in a companion report: "*Volume II – Characterization of the Minnesota Wind Resource"*. Key findings and outcomes from this report are summarized below:

- A county by county assessment map of the wind generation resource was created for the state of Minnesota through the application of GIS techniques to the high-resolution state wind mapping data from the Minnesota Department of Commerce. This process represented a critical component step in formulating the distribution of wind energy production for meeting the year 2020 target of 6000 MW.
- Through the use of extensive numerical modeling for Minnesota and the eastern Dakotas over the years 2003, 2004, and 2005, the wind resource of the region was characterized in terms of normalized hub-height wind speed, power density, capacity factor, and energy production.

- Meteorological time series were generated at 152 locations within the modeling domain for the three years. The time series data were extracted at 5-min intervals while the numerical simulations were proceeding. Each model extraction location represents a 4-km x 4-km region where wind energy generation already exists, is proposed for development, or has development or strategic potential.
- The spatial and temporal variability of the wind resource for Minnesota and the eastern Dakotas was presented along with a description of the meteorology of the Upper Midwest that controls this variability.
- Idealized wind energy geographic dispersion analysis revealed that a progressive increase in the distribution of wind production, utilizing four widely spaced generation areas, substantially reduces the hourly frequency when little or no power was being produced, and increases the hourly frequency of production in the general capacity factor range of 20 to 80% for the ensemble of wind plants. Further, a progressive increase in the distribution of wind production had a dramatic effect on reducing the frequency of very large hourly ramp rates for the ensemble production to values near zero for greatest degrees of geographic dispersion.
- Wind energy forecasting experiments that utilized a computational learning system (CLS) with two forecast models from the National Centers for Environmental Prediction showed considerable skill in both short-term (several hours ahead) and day-ahead (up to 48 hours ahead) time frames. In general, the CLS starts outperforming persistence by one hour into the forecast and shows considerable benefit over persistence by the 3-hour point. In the day-ahead time frame, the CLS forecast yields energy production errors (as a percent of actual energy produced) in the low to mid 20% range.
- An investigation of geographically dispersed wind production forecasts revealed that forecasts for the ensemble of sites were substantially more accurate than for a single site. Forecast errors for power and energy production were reduced by 43% and 30%, respectively, when comparing forecasts from a single site to a forecast for four sites. Similarly large short-term forecast error improvements were also realized as the forecast geographic dispersion increased.

Models and Assumptions

The analytical methodology used for this study is based on chronological simulations of generation unit commitment and dispatch over an extended data record. The "rules" for conducting these simulations must reflect the business rules and operating realities of the system or systems being modeled. Defining these rules and other assumptions so that they can modeled and appropriately factored into the analytical methodology is a critical part of the study process. Scenarios that are substantially out into the future can be especially challenging.

A significant amount of effort was placed into defining the assumptions for the 2020 study scenario through a collaborative process involving the study sponsors and Technical Review Committee (TRC).

The Midwest Independent System Operator (MISO) market and reliability footprints are comprised of thousands of individual generating units, many tens of thousands of megawatts of load, and many thousands of miles of transmission lines. Given the influence of the MISO energy market on the daily operations of the Minnesota companies, along with the geographical expanse of the wind generation to be considered, computer models to simulate generation scheduling and operations across the state of Minnesota must also be large.

Transmission issues for wind generation are not the focus of this study. However, transmission capacity has a direct influence on the function of the wholesale energy market, as transmission losses and congestion are responsible for the differences in prices across the market footprint. These influences are accounted for by using an existing MISO planning model which was selected as the starting point for this study.

The size and makeup of a utility company's "footprint" – the amount of load served, and the type, number, and capability of its generating resources – have important influences on the ability to manage wind generation. MISO is currently well underway with the development of an Ancillary Services Market which will result in consolidation of certain utility control area (or BA, for Balancing Authority) functions. A decision was made by the Technical Review Committee to consider all of the Minnesota companies as a single functional BA for purposes of this study.

The operating characteristics of wind generation increase the need for flexible generation to compensate for changes in the net of load and wind generation. These changes occur across all time scales, from seconds to minutes to hours. Chronological wind generation data from the model and load data from MISO archives were analyzed to estimate the incremental requirements in the various categories of operating reserve. Results of this analysis are shown in Table 1. Reserve requirements for each of the wind generation scenarios are used as inputs to the annual simulations of power system operations from which the operating impacts are quantified.

Table 1: Estimated Operating Reserve Requirement for MN Balancing Authority – 2020 Load

Reserve Category	Base		15% Wind		20% Wind		25% Wind	
	MW	%	MW	%	MW	%	MW	%
Regulating	137	0.65%	149	0.71%	153	0.73%	157	0.75%
Spinning	330	1.57%	330	1.57%	330	1.57%	330	1.57%
Non-Spin	330	1.57%	330	1.57%	330	1.57%	330	1.57%
Load Following	100	0.48%	110	0.52%	114	0.54%	124	0.59%
Operating Reserve Margin	152	0.73%	310	1.48%	408	1.94%	538	2.56%
Total Operating Reserves	**1049**	**5.00%**	**1229**	**5.86%**	**1335**	**6.36%**	**1479**	**7.05%**

RELIABILITY IMPACTS

Several methods were employed to assess the contribution of the wind generation modeled for this study to the reliability of the Minnesota power system. The results were consistent across all of the methods, and show that the effective capacity of wind generation can vary significantly year-to-year. The Effective Load Carrying Capability (ELCC) of the wind generation corresponding to 15% to 25% of Minnesota retail electric sales ranges from around 5% to just over 20% of nameplate capacity (Table 2 through Table 4). The capacity value computation is based upon a rigorous Loss of Load Probability (LOLP) analysis.

Meteorological conditions are the most likely explanation for this variation, as it can affect both electric demand and wind generation. The historical years used as the basis for this study did exhibit some marked differences attributable to weather. The analysis can be expected to improve and converge as more years of data are added to the sample.

Table 2: Capacity Value of Wind Generation for 2003 Load and Wind Patterns

Wind Penetration	Installed Capacity	Effective Load-Carrying Capability (ELCC)	ELCC (relative to installed capacity)
15%	3441 MW	719 MW	20.9%
20%	4582 MW	922 MW	20.1%
25%	5688 MW	969 MW	17.0%

Table 3: Capacity Value of Wind Generation for 2004 Load and Wind Patterns

Wind Penetration	Installed Capacity	Effective Load-Carrying Capability (ELCC)	ELCC (relative to installed capacity)
15%	3441 MW	406 MW	11.8%
20%	4582 MW	547 MW	11.9%
25%	5688 MW	641 MW	11.3%

Table 4: Capacity Value of Wind Generation for 2005 Load and Wind Patterns

Wind Penetration	Installed Capacity	Effective Load-Carrying Capability (ELCC)	ELCC (relative to installed capacity)
15%	3441 MW	156 MW	4.5%
20%	4582 MW	234 MW	5.1%
25%	5688 MW	234 MW	4.1%

Operating Impacts

In the operating time frame – hours to days – wind generation and load follow different cycles. Load exhibits a distinct diurnal pattern through all seasons. Wind generation in the Great Plains exhibits some diurnal characteristics, but is mainly driven by the passage of large scale weather systems that have cycles of several days to a week. It is nearly impossible, therefore, to select a small number of "typical" wind and load days for analysis.

MISO utilizes a computer tool called PROMOD for hour-by-hour analysis of energy market operations and transmission facility utilization. In this program, generating units are committed based on costs, operating characteristics, and transmission constraints, then dispatched to meet the specified load on an hourly basis. It can be used as a "proxy" for the short-term operation of power systems.

Commitment of generating resources when the load is known perfectly results in an optimized solution. These optimized hourly cases show the following impacts of wind generation:

- As more wind energy is added, the production cost and load payments decline. This is due to the displacement of conventional generation and the resulting reduction in variable (fuel) costs.
- Generation from both coal and gas units is displaced.
- Production costs rise with the level of required operating reserves. This is intuitive, since more generation must be available or online.
- Production costs rise slowly from the baseline assumption of 5% total operating reserves to about 7%.
- As the operating reserve requirement is increased, coal units are further displaced in favor of more flexible gas units.

Production costs rise as total operating reserves are increased, which is the expected result. It is recognized, however, that a higher reserve requirement for all hours of the annual simulation is overly conservative, since there are many hours where wind generation is very low, and changes up or down would be of little note to operators. Further, an incremental operating reserve pegged to hourly changes in wind generation would not need to be comprised of spinning generation only – changes in the later part of the hour could be covered by quick-start units, if available. The significance here is that no costs accrue with this type of reserve unless it is used.

A case was run for the 2004 load patterns at 20% wind generation with operating reserves for wind generation modeled less conservatively:

- The additional operating reserve for wind generation is a variable hourly profile based on the previous hourly average value.
- The incremental reserves for wind generation were further required only to be non-spinning.

As expected, these assumptions resulted in a decreased production costs over the fixed additional reserves case.

The cost of the additional reserves required to manage the system with wind generation can be estimated from cases where only the operating reserve requirement is varied. Table 5 documents the production cost results from four cases with differing operating reserve assumptions. It shows that for the treatment of reserves deemed to be the most appropriate, the addition cost is $0.11 per MWH of wind generation delivered to the system.

Table 5: Incremental Reserve Cost for 20% Wind Case, 2004 Patterns

Case	Production Cost
Full Reserves Case	$1,928 M
20% Variable Reserve Margin Case	$1,923 M
Operating Reserve Margin as non-spin	$1,921 M
Base Case - 5% Operating Reserve Assumption	$1,919 M
Wind Production - 20%/2004 Cases	*16,895,658 MWH*
Inremental Cost - "Full" Reserves	$9,368,744
Cost per MWH Wind	**$0.55**
Incremental Cost - "Variable" Reserves	$3,955,303
Cost per MWH Wind	**$0.23**
Incremental Cost - Variable Reserves, non-spin	$1,898,352
Cost per MWH Wind	**$0.11**

The operating cost results show that, relative to the same amount of energy stripped of variability and uncertainty of the wind generation, there is a cost paid by the load that ranges from a low $2.11 **(**for 15% wind generation, based on year 2003) to a high of $4.41 (for 25% wind generation, based on year 2005) per MWH of wind energy delivered to the Minnesota companies. This is a total cost and includes the cost of the additional reserves (per the assumptions) These results are shown graphically in Figure 2.

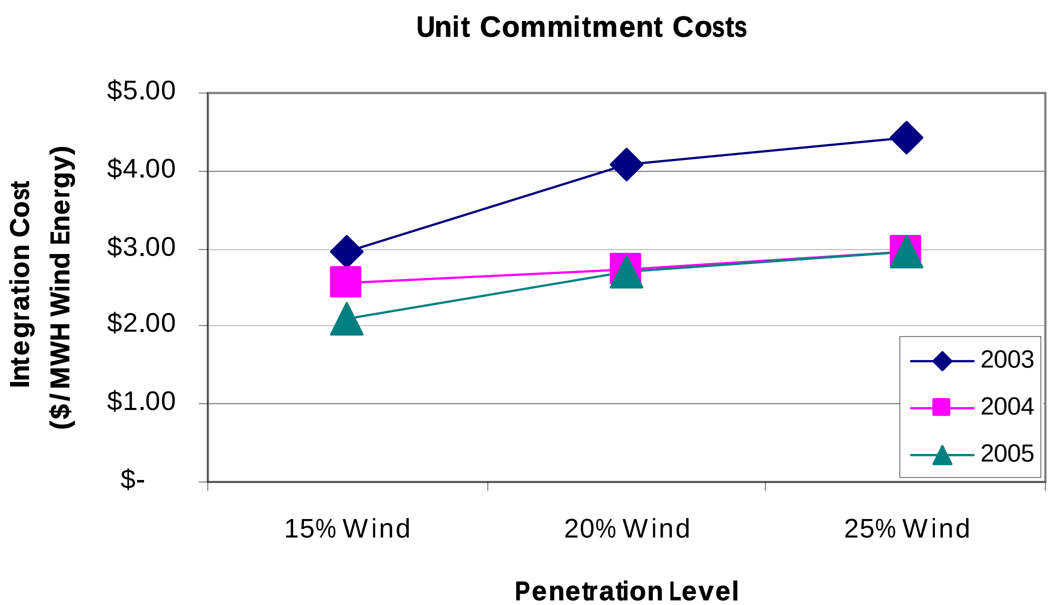


Figure 2: Unit commitment costs for three penetration levels and pattern years. Cost of incremental operating reserves is embedded.

STUDY CONCLUSIONS

The analytical results from this study show that the addition of wind generation to supply 20% of Minnesota retail electric energy sales can be reliably accommodated by the electric power system if sufficient transmission investments are made to support it.

The degree of the operational impacts was somewhat less than expected by those who have participated in integration studies over the past several years for utilities around the country. The technical and economic impacts calculated are in the range of those derived from other analyses for smaller penetrations of wind generation.

Discussion of the analytical results with the Technical Review Committee and the Minnesota utility company representatives has established the following as the key findings and the principal reasons that wind generation impacts were not larger:

1. These results show that, relative to the same amount of energy stripped of variability and uncertainty of the wind generation, there is a cost paid by the load that ranges from a low of $2.11 (for 15% wind generation, based on year 2003) to a high of $4.41 (for 25% wind generation, based on year 2005) per MWH of wind energy delivered to the Minnesota companies. This is a total cost and includes the cost of the additional reserves (per the assumptions) and costs related to the variability and day-ahead forecast error for wind generation.
2. The cost of additional reserves above the assumed levels attributable to wind generation is included in the total integration cost. Special hourly cases were run to isolate this cost, and found it to be about $0.11/MWH of wind energy at 20% penetration by energy.
3. The TRC decision to combine the Minnesota balancing authorities into a single functional balancing authority had a significant impact on results. Sharing balancing authority functions substantially reduces requirements for certain ancillary services such as regulation and load following (with or without wind generation). The required amount of regulation capacity is reduced by almost 50%. Additional benefits are found with other services such as load following. In addition, there are a larger number of discrete units available to provide these services.
4. The expanse of the wind generation scenario, covering Minnesota and the eastern parts of North and South Dakota, provides for substantial "smoothing" of wind generation variations. This smoothing is especially evident at time scales within the hour, where the impacts on regulation and load following were almost negligible. Smoothing also occurs over multiple hour time frames, which reduces the burden on unit commitment and dispatch, assuming that transmission issues do not intervene to affect operations. Finally, the number of hours at either very high or very low production are reduced, allowing the aggregate wind generation to behave as a more stable supply of electric energy
5. The transmission expansion as described in the assumptions and detailed in Appendix A combined with the decision to inject wind generation at high voltage buses was adequate for transportation of wind energy in all of the scenarios. Under these assumptions, there were no significant congestion issues attributable to wind generation and no periods of negative Locational Marginal Price (LMP) observed in the hourly simulations.
6. The MISO energy market also played a large role in reducing wind generation integration costs. Since all generating resources over the market footprint are

committed and dispatched in an optimal fashion, the size of the effective system into which the wind generation for the study is integrated grows to almost 1200 individual generating units. The aggregate flexibility of the units on line during any hour is adequate for compensating most of the changes in wind generation.

The magnitude of this impact can be gauged by comparing results from recent integration studies for smaller systems. In the 2004 study for Xcel Energy, for example, integration costs were determined to be no higher than $4.60/MWH for a wind generation penetration by capacity of 15%, which would be closer to 10% penetration on an energy basis.

7. The contribution of wind generation to power system reliability is subject to substantial inter-annual variability. Annual Effective Load Carrying Capability (ELCC) values for the three wind generation scenarios from rigorous Loss of Load Probability (LOLP) analysis ranged from a low of 5% of installed capacity to over 20%. These results were consistent with those derived through approximate methods.

Project and Report Overview

EnerNex Corporation, of Knoxville, Tennessee was selected to be the prime contractor for the study. WindLogics, of St. Paul, Minnesota was subcontracted by EnerNex to perform the wind resource characterization and develop the long-term chronological wind speed data sets upon which the analyses of the Minnesota power system were based.

The study was conducted through an open and transparent process that involved the Commission, technical representatives from the Minnesota utility companies, the Midwest Independent System Operator, and stakeholder groups, along with technical experts in wind generation from across the country. The approach, data, assumptions, and analytical methodology were reviewed and extensively discussed at review meetings over the course of the project. Interim results were presented and evaluated, with recommendations from this Technical Review Committee (TRC) guiding subsequent analyses.

The technical scope for the project was based on the original Request-for-Proposal from the Minnesota Public Utilities Commission. As the project progressed, some revisions to this original scope were necessary as a result of assumptions and decisions made in conjunction with the TRC. This report documents the project as conducted.

The contribution of the Midwest Independent System Operator to this effort was very significant. Analysis of an electric power system of the geographic extent and operation complexity considered in this study would have been extremely difficult if not impossible without the support and collaboration of the MISO engineering staff. The project team thanks MISO staff for their efforts and significant contribution.

This report is comprised of four main sections. In Section 2, the approach used to develop the chronological wind generation data so critical to the analytical methodology is described. Characterizations of the wind resource in the state of Minnesota are also presented, and are documented in detail in the companion volume to this report.

Section 3 details the assumptions made in conjunction with the project Technical Review Committee to govern the analysis. Data comprising the models of the electric power system in Minnesota to be used in the analysis are also described. Analysis and assumptions regarding the impact of wind generation on system reserve requirements is presented.

In Section 4 the analytical approach to determining the contribution of the wind generation model to system reliability is documented, along with results of the analytical procedures and conclusions.

Finally, Section 5 details how wind generation affects the operation of the Minnesota power system, as determined from annual hour-by-hour simulations of generation unit commitment and dispatch.

Section 1

INTRODUCTION

In 2005 the Minnesota Legislature adopted a requirement for a study "of the impacts on reliability and costs associated with increasing wind capacity to 20% of Minnesota retail electric energy sales by the year 2020, and to identify and develop options for utilities to use to manage the intermittent nature of wind resources." The office of the Reliability Administrator of the Minnesota Public Utilities Commission was assigned responsibility for management of the study.

All utilities with Minnesota retail electric sales participated in this study (totaling approximately 62,000 GWH in 2004). Eight Balancing Authorities are represented with over 85% of the retail sales in the four largest Balancing Authorities: Xcel (NSP), Great River Energy, Minnesota Power, and Otter Tail Power. Projected to 2020, 20% of retail sales will require approximately 5,000 MW of total wind generation. The study area is within the Midwest Reliability Organization (MRO) NERC reliability region and the Mid-Continent Area Power Pool (MAPP) Generation Reserve Sharing Pool. Nearly 95% of the retail sales are within the Midwest Independent System Operator (MISO). Prior wind integration studies of relevance include the 2004 Xcel Energy / MN DOC study and the 2005 NYSERDA / NYISO study. Recent and current regional power studies of relevance include the 2006 MISO Transmission Expansion Plan, the 2003 MAPP Reserve Capacity Obligation Review, and CapX 2020 transmission planning.

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 a 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 effects of physical separation 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.

Overview of Utility System Operations

Short-Term Planning and Real-Time Operation

Interconnected power systems are large and extremely complex machines, consisting of tens 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, require 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 reactive power 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 Reliability Organizations (RROs), which oversee and coordinate activities across a number of control areas for the purposes of maintaining the security of the interconnected power systems.

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

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, a rigorous 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 are important questions.

Influence of the MISO Market on Minnesota Utility Company Operations

Electric power industry developments over the past two decades have brought a new framework for system planning and operations. Traditional utility company functions such as the commitment and scheduling of generation have been supplanted by new mechanisms that seek to optimize operation of the electric supply and transportation system over a footprint much larger than a single utility company service territory.

MISO wholesale energy markets have changed the process by which Minnesota utility companies commit and schedule generation and buy and sell energy to meet their load obligations. It has been found in previous wind generation integration studies that modeling the “business environment” in the analytical methodology can have a significant effect on the results. As such, the operation of the MISO markets is a major consideration in the analytical methodology assembled for this study.

Project Organization

EnerNex Corporation, of Knoxville, Tennessee was selected to be the prime contractor for the study. WindLogics, of St. Paul, Minnesota was subcontracted by EnerNex to perform the wind resource characterization and develop the long-term chronological wind speed data sets upon which the analyses of the Minnesota power system were based.

The study was conducted through an open and transparent process that involved the Commission, technical representatives from the Minnesota utility companies, the Midwest Independent System Operator, and stakeholder groups, along with technical experts in wind generation from across the country. The approach, data, assumptions, and analytical methodology were reviewed and extensively discussed at review meetings over the course of the project. Interim results were presented and evaluated, with recommendations from this Technical Review Committee (TRC) guiding subsequent analyses.

The technical scope for the project was based on the original Request-for-Proposal from the Minnesota Public Utilities Commission. As the project progressed, some revisions to this original scope were necessary as a result of assumptions and decisions made in conjunction with the TRC. This report documents the project as conducted.

The contribution of the Midwest Independent System Operator to this effort was very significant. Analysis of an electric power system of the geographic extent and operation complexity considered in this study would have been extremely difficult if not impossible without the support and collaboration of the MISO engineering staff. The project team thanks MISO staff for their efforts and significant contribution.

REPORT OVERVIEW

This report is comprised of four main sections followed by conclusions. In Section 2 “Characterizing the Minnesota Wind Resource”, the approach used to develop the chronological wind generation data so critical to the analytical methodology is described. Characterizations of the wind resource in the state of Minnesota are also presented, and are documented in detail in the companion volume to this report.

Section 3 “Models and Assumptions” details the assumptions made in conjunction with the project Technical Review Committee to govern the analysis. Data comprising the models of the electric power system in Minnesota to be used in the analysis are also described. Analysis and assumptions regarding the impact of wind generation on system reserve requirements is presented.

In Section 4 “Reliability Impacts”, the analytical approach to determining the contribution of the wind generation model to system reliability is documented, along with results of the analytical procedures and conclusions.

Finally, Section 5 “Operating Impacts” details how wind generation affects the operation of the Minnesota power system, as determined from annual hour-by-hour simulations of generation unit commitment and dispatch.

Section 2

CHARACTERIZING THE MINNESOTA WIND RESOURCE

Variability and uncertainty are the two attributes of wind generation that underlie most of the concerns related to power system operations and reliability. In day-ahead planning, whether it be for conventional unit commitment or offering generation into an energy market, forecasts of the demand for the next day will drive the process. In real-time operations, generating resource must be maneuvered to match the ever-changing demand pattern. To the extent that wind generation adds to this variability and uncertainty, the challenge for meeting demand at the lowest cost while maintaining system security is increased.

Recent studies have shown that a high-fidelity, long-term, chronological representation of wind generation is perhaps the most critical element of this type of study. For large wind generation development scenarios, it is very important that the effects of spatial and geographic diversity be neither under- or over-estimated. The approach for this task has been used by EnerNex and WindLogics in at least six wind integration studies, including the Minnesota study of the Xcel system completed in 2004 for the Minnesota Department of Commerce.

The initial task of this project was focused on characterizing the wind resource in Minnesota and developing chronological wind speed and wind generation forecast data for use in later analytical tasks. The procedure and results of this effort are documented in detail in a companion report (Volume II).

SYNTHESIS OF WIND SPEED DATA FOR THE MN WIND GENERATION SCENARIOS

The base data for both the wind resource characterization and the production of wind speed and power time series were generated from the MM5 mesoscale model (Grell et al. 1995). This prognostic regional atmospheric model is capable of resolving mesoscale meteorological features that are not well represented in coarser-grid simulations from the standard weather prediction models run by the National Centers for Environmental Prediction (NCEP). The MM5 was run in a configuration utilizing two grids as shown in Fig. 1. This "telescoping" two-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 were not as important. This methodology was computationally efficient while still providing the necessary resolution for accurate representation of the meteorological scales of interest within the inner grid.

More specifically, the 4 km innermost grid spacing was deemed necessary to capture topographic influences on boundary layer flow and resolve mesoscale meteorological phenomena such as thunderstorm outflows. The 12 and 4 km grid spacing utilized in grids 1 and 2, respectively, yield the physical grid sizes of 2400 x 2400 km for grid 1, and 760 x 760 km for grid 2.

To provide an accurate assessment of the character and variability of the wind resource for Minnesota and the eastern Dakotas, three full years of MM5 simulations were completed. To initialize the model, the WindLogics archive of NCEP Rapid Update Cycle (RUC) model analysis data was utilized. The years selected for simulation were 2003, 2004 and 2005. The RUC analysis data were used both for model initialization and for updating the model boundary conditions every 3 hours. This RUC data had a horizontal grid spacing of 20 km for all three years.

A Minnesota wind development scenario was constructed to support the development of the wind generation model for the analytical tasks. The target penetration level is based on a fraction of projected retail electricity sales in the 2020 study year, which from Table 6 is estimated to be 20% of 85,093 GWH. The next step in defining the scenario is to determine the actual installed wind generation capacity, which requires an estimate of the aggregate annual capacity factor. From this, the number of extraction points in the meteorological simulation model to reasonably represent the total installed capacity can be determined.

Table 6: 2020 Projections of Minnesota electric retail sales and wind generation at assumed annual capacity factors.

Retail Sales Annual Growth Rate	Wind Percent Retail Sales	Wind Annual Capacity Factor		2004	**2011**	**2020**
1.0%			MN Retail Sales (GWh)	61,986	66,457	72,683
	15%	40%	Nameplate wind (MW)	2,653	2,845	3,111
	20%	35%		4,043	4,335	4,741
	20%	40%		3,538	3,793	4,149
	25%	40%		4,422	4,741	5,186
2.0%			MN Retail Sales (GWh)	61,986	71,202	85,093
	15%	**40%**	Nameplate wind (MW)	2,653	**3,048**	**3,643**
	20%	35%		4,043	4,645	5,551
	20%	**40%**		3,538	**4,064**	**4,857**
	25%	**40%**		4,422	**5,080**	**6,071**

Data at 152 grid points (proxy towers) in the inner model nest were extracted every 5 min as the simulation progressed through historical years 2003, 2004, and 2005. This process ensured that the character and variability of the wind resource over several time scales across geographically dispersed locations is captured. Figure 3 depicts the MM5 innermost grid with selected locations for high time-resolution data extraction shown in Figure 3 and Figure 4. The sites were selected in coordination with the utility and government stakeholders represented on the Technical Review Committee to correspond to 1) existing wind plant locations such as those along the Buffalo Ridge and other regions of southern Minnesota, 2) proposed locations for near-future wind plant development or 3) favorable locations for future wind production with emphasis given to a distribution of wind energy plants that would provide beneficial geographic dispersion. The 2005 Minnesota Department of Commerce high resolution state wind map was used, in part, for guidance in assessing favorable development areas. Overall, 152 sites were located in 62 counties in the three state domain at locations within the county with an expected favorable wind resource. Consideration was also given to the existence of nearby transmission and substations. Model data extracted at each site included wind direction and speed, temperature and pressure at 80 and 100 m hub heights.

Each data extraction point was assigned to one or more of the wind generation scenarios to be considered in the study. The TRC was consulted to help define the makeup of each scenario. The result of these discussions is shown in Figure 5. The 15% scenario includes all of the existing wind generation, which is mostly on the

Buffalo Ridge, and adds sites distributed across the region. The increment to 20% wind generation continues with the addition of distributed sites. To reach the 25% penetration level, the remaining data extraction points in the model are added, with the bulk of these located on the Buffalo Ridge.

The non-wind variables were extracted to calculate air density that is used along with the wind speed in turbine power calculations. With this data, Wind Logics developed time series of 80 and 100 m wind speed and power at 5 minute and 1 hour time increments for use by EnerNex in system modeling efforts described in later analytical efforts.

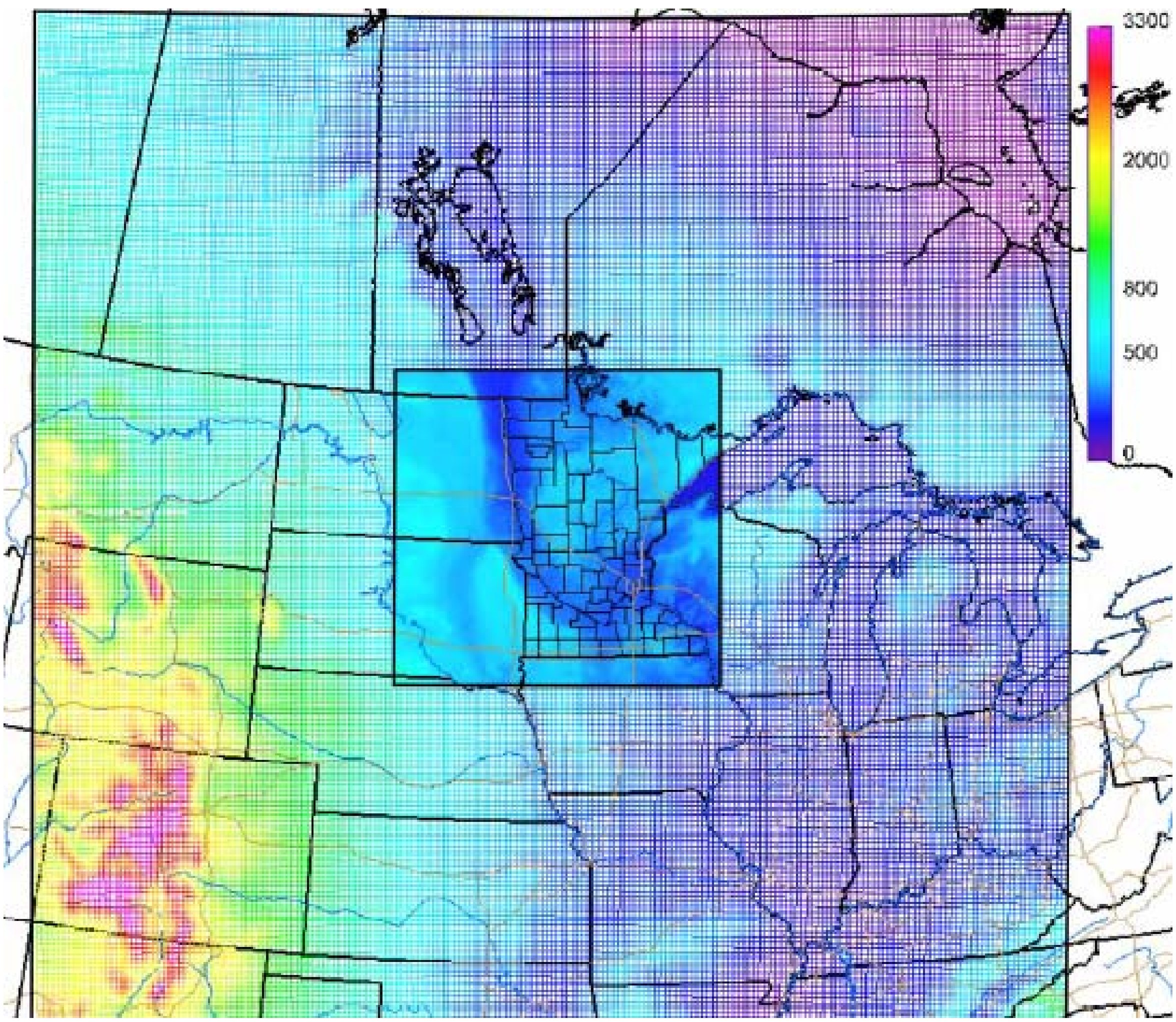


Figure 3: Inner and outer nested grids used in MM5 meteorological simulation model.

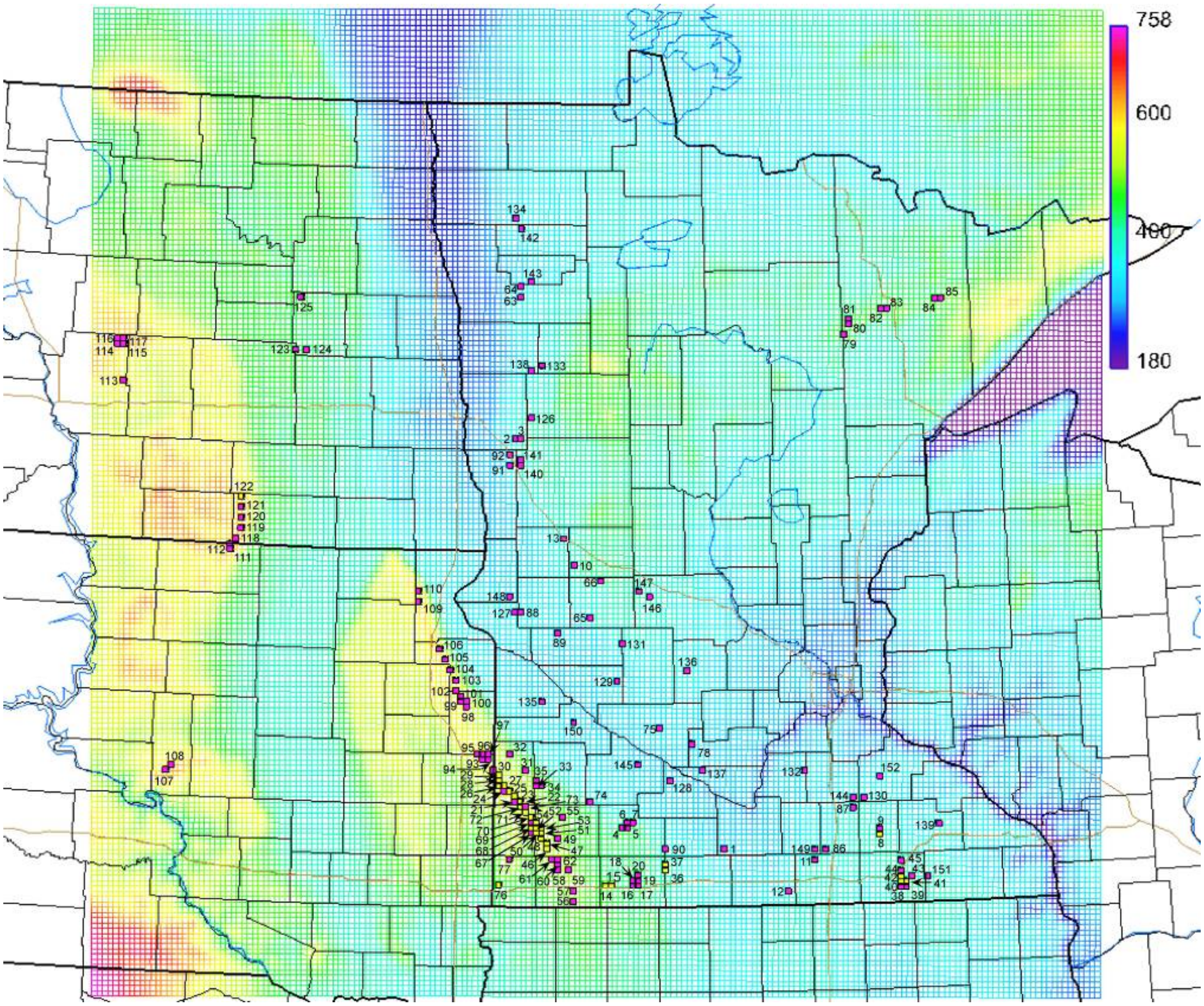


Figure 4: Location of "proxy towers" (model data extraction points) on inner grid (yellow are existing / contracted).

Results of the meteorological simulations were summarized in a variety charts and graphs that illustrate the nature of the wind resource in Minnesota. Figure 6 and Figure 7 show just a few of these, and illustrate the mean annual wind speed and estimated net capacity factor for a turbine with an 80 m hub-height.

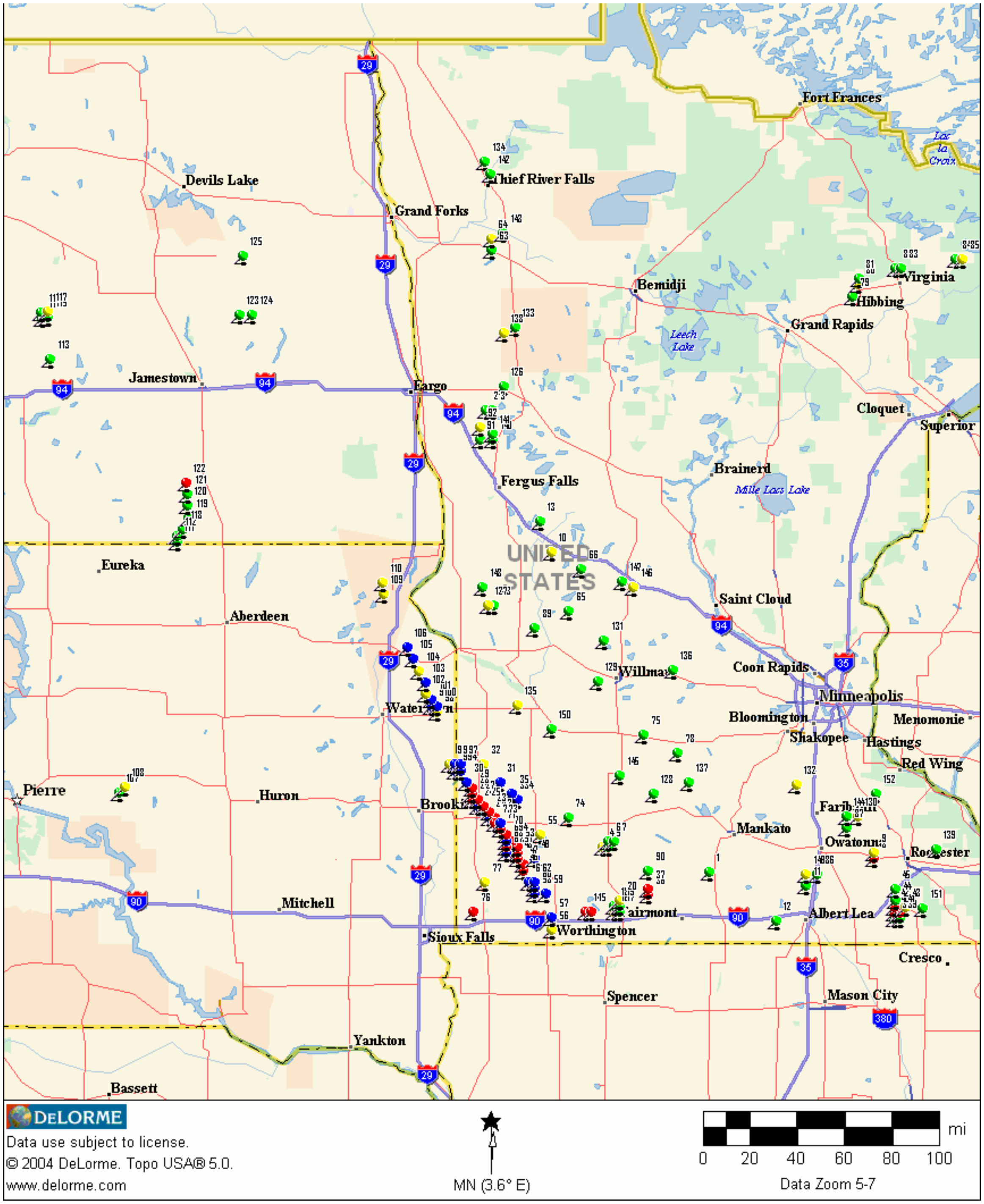


Figure 5: Location of "proxy towers" in MM5 nested grid model. Legend: - Red: Existing wind generation; Green: Additional sites for 15% scenario; Yellow: Additional sites for 20% scenario; Blue: Additional sites for 25% scenario

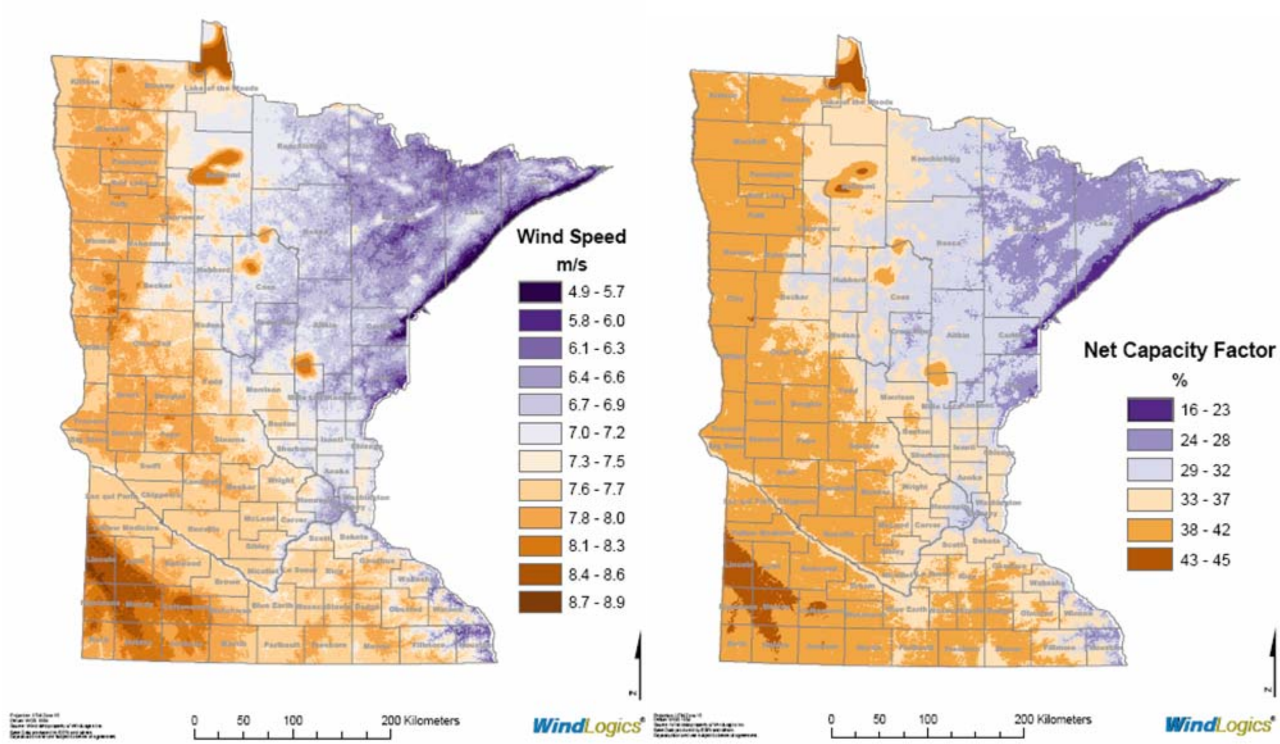


Figure 6: Mean annual wind speed at 80 m AGL (r) and net annual capacity factor (l).

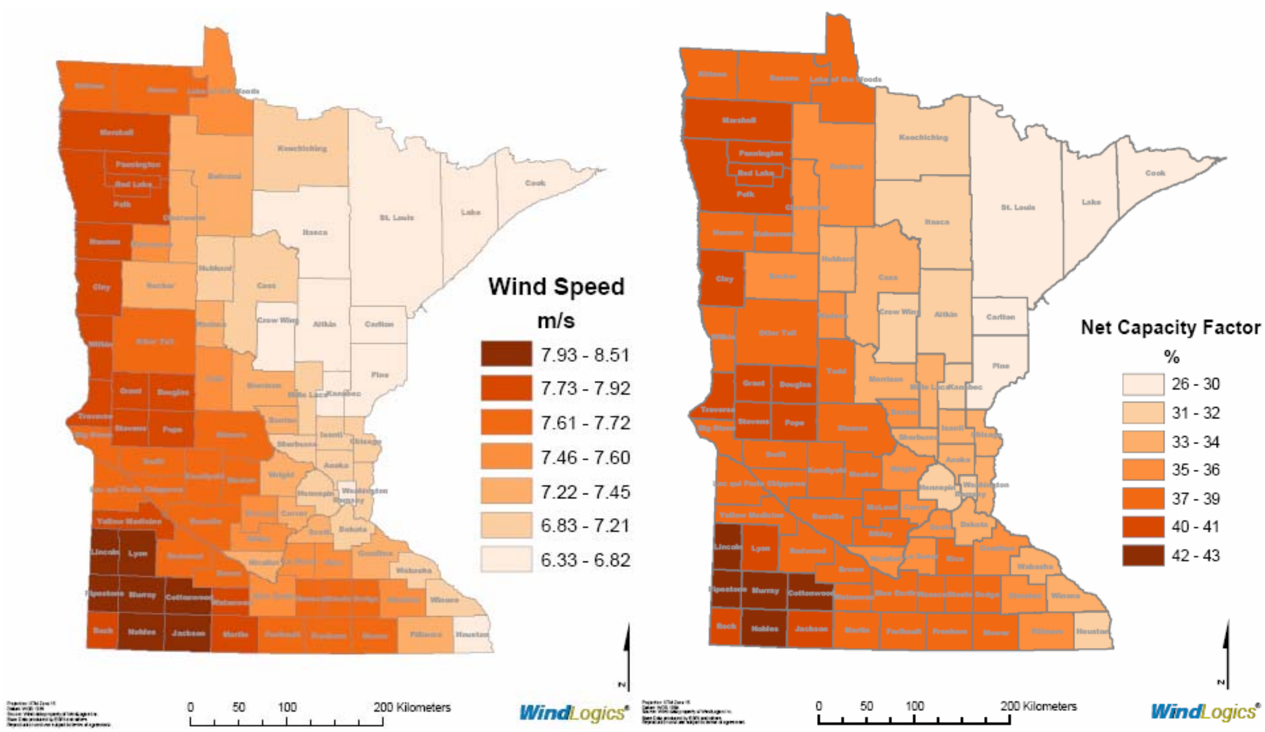


Figure 7: Mean annual wind speed at 80 m AGL (r) and net annual capacity factor assuming 14% losses from gross and Vestas V82 1.65 MW MkII power curve, (left) by county.

WIND GENERATION FORECASTS

The uncertainty attribute of wind generation stems from the errors in forecasts of wind generation over forward periods. Because this attribute is to be explicitly represented in the later analytical tasks, a companion time series of wind generation forecasts for a time period 18 to 42 hours in the future was developed. This corresponds to the forecast that would be used for generation unit commitment in general, or participation in day-ahead market in the case of MISO. Information on short-term forecasting (one to a few hours ahead) was utilized in the assessment of wind generation impacts on real-time operation of the power system.

The day-ahead 24-hour forecast time series used for the hourly analysis described later in the report has a mean absolute error of around 20% of rated capacity.

Further information on the development and assessment of wind generation forecasting can be found in the Volume II report.

SPATIAL AND GEOGRAPHIC DIVERSITY

When wind generation is an appreciable fraction of the supply picture, variations in production over time drive the need for maneuverable generation to compensate. The nature of the wind generation changes over various operational time scales from minutes to multiple hours is a critical consideration in assessing wind integration costs. The variation of the aggregate wind generation resource is very much affected by the location of the wind turbines and wind plants with respect to each other, as illustrated in Figure 8. As the distance between individual wind turbines, then individual wind plant on a larger scale grows, production variation exhibit less correlation (a correlation coefficient of 1.0 means that the changes happen at the same time; a coefficient of 0.0 means that the changes are not related). The consequence for system operations is that spatially and geographically dispersed wind generation will be less variable in the aggregate than the same amount of wind generation concentrated at a single site or within a single region.

The effects of spatial and geographic diversity were quantified for this study through analysis of the wind generation data developed from meteorological simulations. Figure 9 shows the hourly changes in wind generation for a single location along with combinations of regionally-dispersed locations. Reduction in the hourly variability due to the aggregation of individual wind generation sources over the region is very evident from the plot.

Figure 10 illustrates another significant effect of geographic diversity. The distribution of hour production over an annual period is shown for scenarios of increasing geographic diversity. As wind generation from an increasing number of geographically separated locations in the region is aggregated, the number of very high and very low production hours drops substantially. Hours at production levels between the extremes is increased. This influence has important implications for power system operations, as will be seen later.

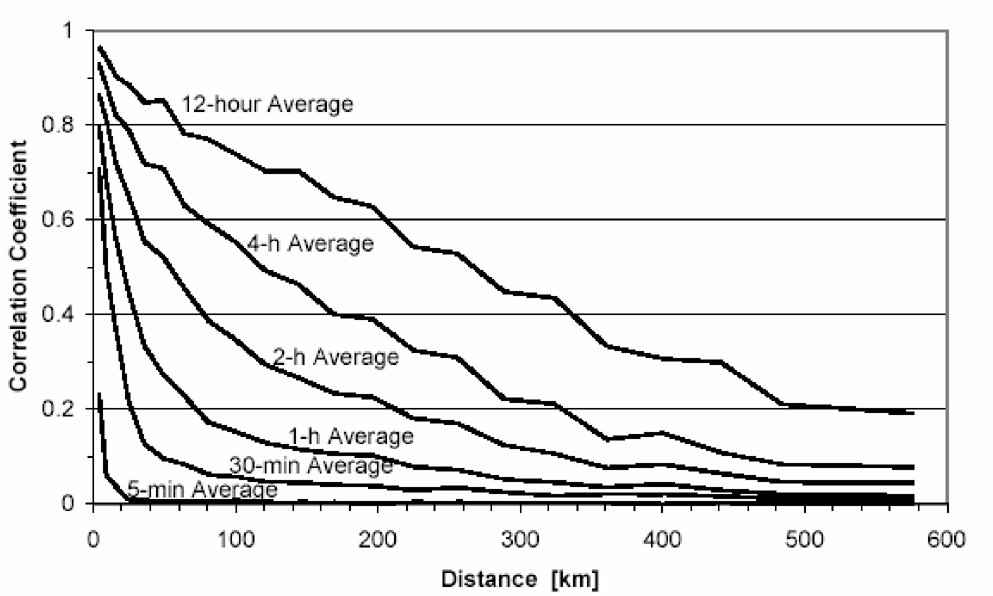


Figure 8: Correlation of wind generation power changes to distance between plants/turbines. From NREL/CP-500-26722, July, 1999

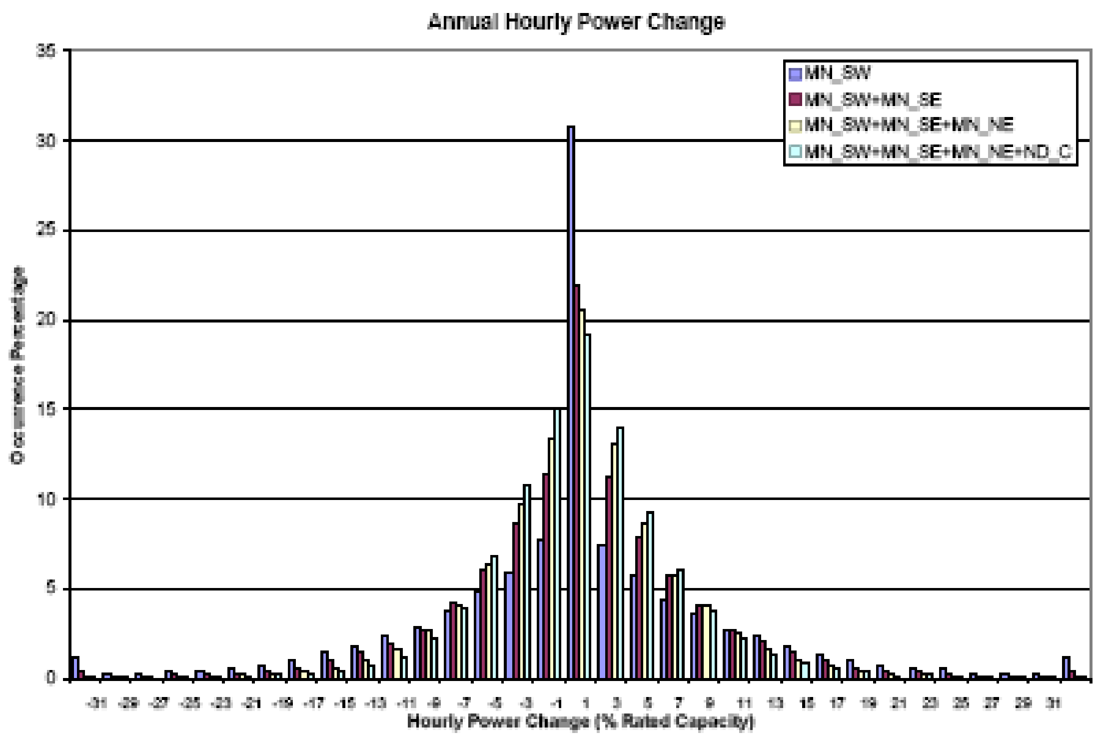


Figure 9: Reduction in hourly variability (change) of wind generation as wind generation over the region is aggregated.

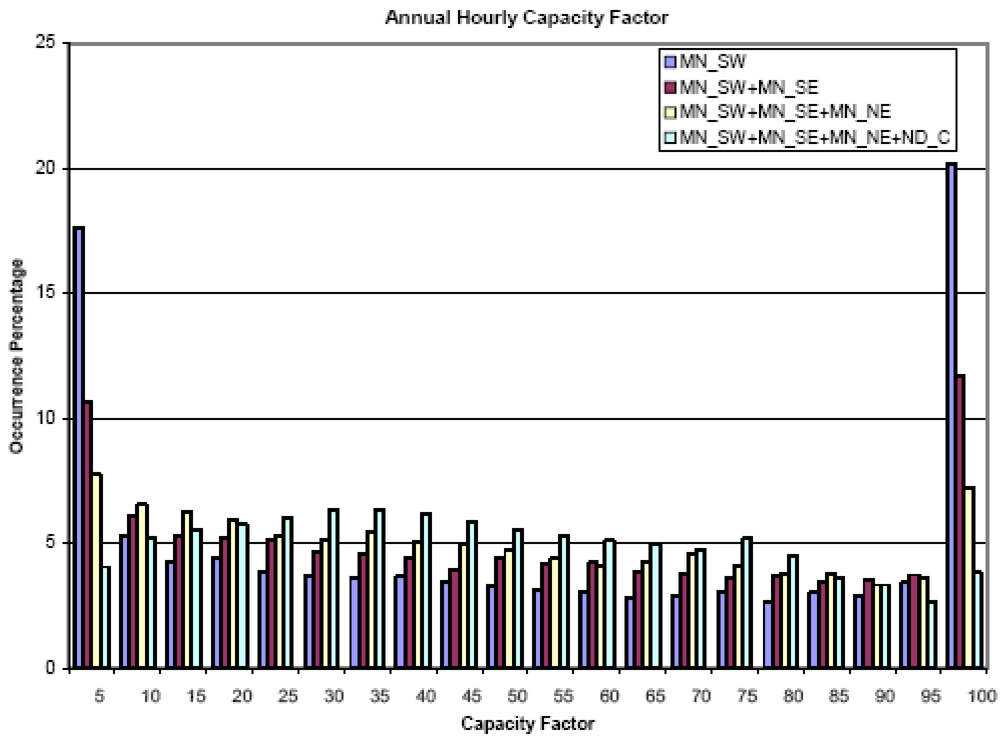


Figure 10: Annual histogram of occurrence percentage of hourly capacity factor for four levels of geographic dispersion. Data is based on hourly performance for the Vestas V82 1.65 MW turbine and reflects gross capacity factors. See legend for specific geographic dispersion scenario. Note: MN_SW = Minnesota Southwest, MN_SE = Minnesota Southeast, MN_NE = Minnesota Northeast, and ND_C = North Dakota Central.

Section 3

MODELS AND ASSUMPTIONS

The analytical methodology used for this study is based on chronological simulations of generation unit commitment and dispatch over an extended data record. The "rules" for conducting these simulations must reflect the business rules and operating realities of the system or systems being modeled. Defining these rules and other assumptions so that they can be modeled and appropriately factored into the analytical methodology is a critical part of the study process. Scenarios that are substantially out into the future can be especially challenging since many of the rules and regulations that govern current-day power system operations may no longer be relevant to the time of interest.

A significant amount of effort was placed into defining the assumptions for the 2020 study scenario through a collaborative process involving the study sponsors and Technical Review Committee. The purpose of this section is to describe and document those assumptions.

MISO MARKET STRUCTURE

Power system operation is governed by both technical and economic considerations. On the technical side, system security must be maintained at all times, and the dispatching of generation to meet obligations (primarily serving load plus delivering on promises to buy or sell energy) must be performed in a manner which constitutes acceptable control performance. The economic objective is to meet these obligations in the most favorable financial sense, based on minimizing variable operating costs within the market.

Startup of MISO energy market operations has brought some significant changes to the way that Minnesota utilities manage their generating resources. In essence, under MISO market operations, the Minnesota utility companies pool their resources and obligations with other MISO market participants. The market then determines what resources are used to meet load in the most economic manner while respecting all constraints on individual units, the needs of the system as a whole, transmission facilities, and considerations for secure operation.

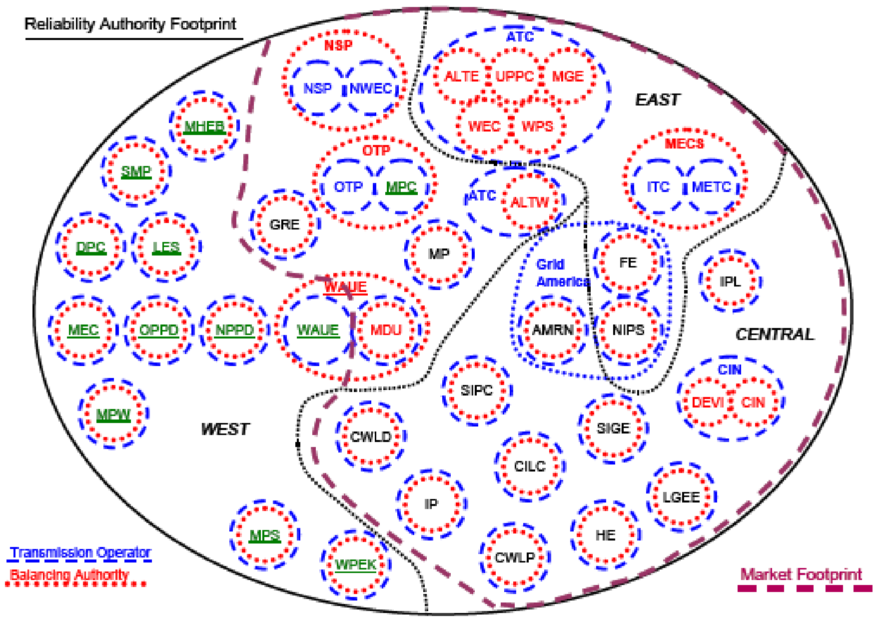
The arrangement of the MISO market and reliability authority footprint is shown in Figure 11. MISO operates a daily Day-Ahead Energy Market that closes at 11:00 am the day prior to the operating day, and a Real-Time energy market that closes 30 minutes prior to the Operating Hour. Energy cost in the day-ahead and real-time market is based on the highest priced energy that is offered into the market and is required to meet load, or "cleared". All generators are paid the clearing price for that period and all loads pay the clearing price for that time period. The net of payments results in simply a net cost of fuel for energy supplied to a utility's loads from its owned portfolio of resources. The portion of utility load supplied from the market resources pays a net delivered purchased power price. Because transmission congestion and losses may prevent a generator in one physical part of the market from serving load in another part, the clearing price will vary by location. Another term for this geographically-varying price is *locational marginal price*, or “LMP”.

At present, the MISO market structure accepts output from wind generation resources “as delivered”, recognizing its fundamental inability to follow dispatch instructions. The financial supply cost optimization that occurs in the market automatically ramps down energy supply from the least efficient dispatchable generators in response to increases in wind generation that occur as a trend over many minutes. Conversely, the market will increase supply from the next most efficient available units in response to reductions in wind generation output that occur over many minutes.

The effect of the MISO market overlay extends beyond the day-ahead energy time frame. To facilitate the real-time market which is cleared at five minute intervals, it is necessary for MISO to have influence on the real-time dispatch of generation within each control area in the footprint. Figure 12 illustrates this structure. It should be noted that this represents a more sophisticated grid control and dispatch than traditional control area or control center operations. The net effect is that the real-time operation of all control areas within the market footprint is coordinated via this hierarchical structure. In more conventional operations, each control area is on its own with respect to balancing supply and demand and honoring scheduled transactions with neighbors.

There are currently 37 individual control areas within the MISO reliability footprint (Table 7). Not all of these control areas participate in the energy markets, but nonetheless are impacted by MISO dispatch and generation control structure. Development of MISO’s Ancillary Services Market (ASM) is well underway and will result in consolidation of certain balancing authority (control area) functions. The effect of such functional consolidation, as will be discussed later, will be to reduce the quantity of services required to maintain system security and control performance across the footprint. The ASM will transfer the source of short-interval responses to changes in wind output from today’s default of the individual utility control areas to the least-cost supply option available from the broader market footprint.

Exhibit 2-6: Midwest ISO Regions (West/Central/East)



Note 1: Systems under Midwest ISO Reliability Authority but not under the Energy Markets are shown as underlined.
Note 2: MDU is a pseudo Balancing Authority under Midwest ISO.
Note 3: ITC and METC are treated as separate Balancing Authorities for the Energy Markets.

Figure 11: Structure of MISO market and reliability footprints. (from MISO Business Practices Manual) Note: Southern Minnesota Municipal Power Agency is now a MISO market participant; LGE is leaving MISO).

Analytical Approach

The technical analysis falls into two general categories – Reliability and Operating Impacts. The data and tools to be used to assess the impacts of the defined wind generation are described below.

Reliability Analysis

The objective here is to determine to what extent wind generation would reduce the need for additional conventional capacity. This analysis involves assessing the probability of not being able to meet load in any given hour over a period due to outage of generating units. “LOLP” stands for “loss of load probability” and is the metric which defines the reliability of a system. A LOLP of one day in ten years, or 2.4 hours per year, a common target reliability level, is used in this analysis.

The reliability analysis is performed with two different tools. The first is GE-MARS (Multi-Area Reliability Simulation) from GE Energy which has been used by the MAPP Generation Reserve Sharing Pool in recent years to analyze the Reserve Capacity Obligation. The database compiled for the 2003 study conducted by GE for MAPP was obtained. The database was updated to reflect the generation expansion for the 2020 study year, and Minnesota load was increased as described in later sections of this document.

Wind generation was represented as a load modifier, meaning that the hourly demand in the Minnesota "area" in the MARS input data is the net of load and wind for each hour of the year. The analysis was conducted for three different "versions" of 2020, where the hourly wind and load patterns are based on the historical years 2003, 2004, and 2005. Using three years rather than a single year provides a relatively better characterization of the wind production during periods of high demand or risk to the system than would be obtained with just a single year.

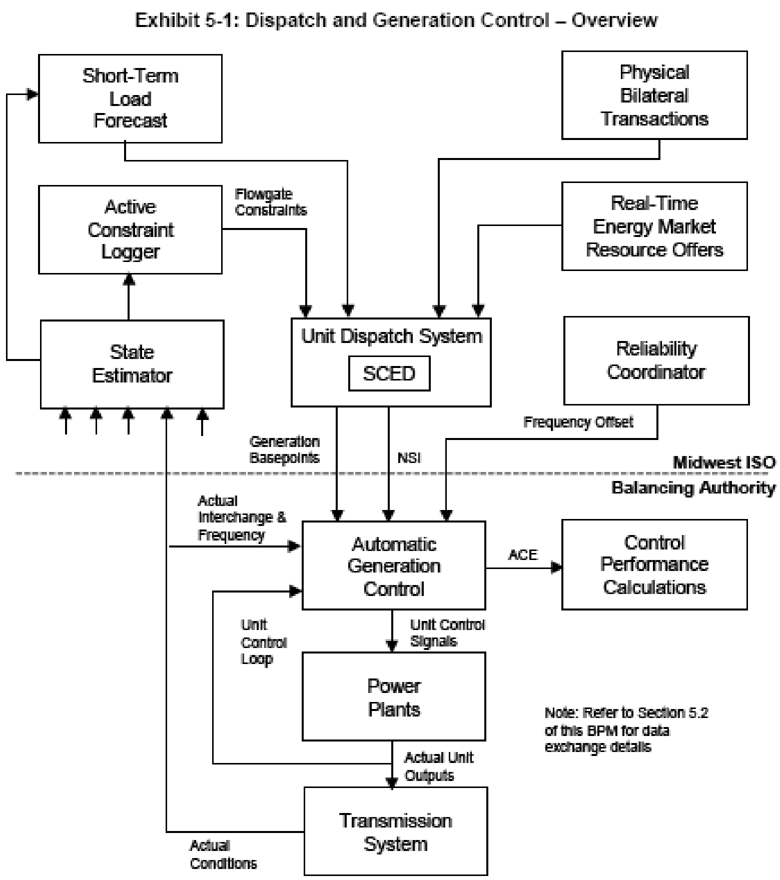


Figure 12: MISO structure for generation dispatch and control.

Table 7: Control Areas within MISO's Reliability Authority Footprint

	Balancing Authority Name	BA	Under MISO Market Note 4		Under MISO RA Note 5		NERC Region	Reliability Authority Note 3		Transmission Operator
								Carmel	St. Paul	
1	Alliant Energy - CA - ALTE	ALTE	Yes	4	Yes	2,691	MAIN	E		ATC
2	Alliant Energy - CA - ALTW	ALTW	Yes	4	Yes	3,932	MAIN		W	ATC
3	Ameren Transmission	AMRN	Yes	1	Yes	12,806	MAIN	C		AMRN, Grid America
4	Central Illinois Light Co	CILC	Yes	1	Yes	1,268	MAIN	C		CILC
5	Cinergy Corporation	CIN	Yes	2	Yes	12,087	ECAR	C		CIN
6	Columbia Water & Light (Columbia, MO)	CWLD	Yes	1	Yes	305	MAIN	C		CWLD
7	City Water, Light & Power (Springfield, IL)	CWLP	Yes	1	Yes	479	MAIN	C		CWLP
8	DECA, LLC - Vermillion (Note 5)	DEVI	Yes	6	Yes	640	ECAR	C		CIN
9	Dairyland Power Cooperative	DPC	No		Yes		MAPP		W	DPC
10	First Energy Corp.	FE	Yes	2	Yes	13,238	ECAR	E		FE, Grid America
11	Great River Energy	GRE	Yes	1	Yes	2,570	MAPP		W	GRE
12	Hoosier Energy Rural Electric Co., Inc.	HE	Yes	1	Yes	1,216	ECAR	C		HE
13	Illinois Power Co.	IP	Yes	2	Yes	4,204	MAIN	C		IP
14	Indianapolis Power & Light Company	IPL	Yes	2	Yes	3,065	ECAR	C		IPL
15	Lincoln Electric System	LES	No		Yes		MAPP		W	LES
16	LG&E Energy Transmission Services	LGEE	Yes	2	Yes	7,042	ECAR	C		LGEE
17	MidAmerican Energy Company	MEC	No		Yes		MAPP		W	MEC
18	Michigan Electric Coordinated System (Note 1)	MECS	Yes	3	Yes	23,550	ECAR	E		ITC, METC, Wolverine
19	Madison Gas and Electric Company	MGE	Yes	4	Yes	785	MAIN	E		ATC
20	MHEB, Transmission Services	MHEB	No		Yes		MAPP		W	MHEB
21	Minnesota Power, Inc.	MP	Yes	1	Yes	1,670	MAPP		W	MP
22	Aquila Networks – Missouri Public Service	MPS	No		Yes		SPP		W	MPS
23	Muscatine Power and Water	MPW	No		Yes		MAPP		W	MPW
24	Northern Indiana Public Service Company	NIPS	Yes	2	Yes	3,415	ECAR	E		NIPS, Grid America
25	Nebraska Public Power District	NPPD	No		Yes		MAPP		W	NPPD
26	Northern States Power Company (Xcel Energy)	NSP	Yes	2	Yes	8,595	MAPP		W	NSP, NWEC
27	OPPD CA/TP	OPPD	No		Yes		MAPP		W	OPPD
28	Otter Tail Power Company	OTP	Yes	1	Yes	2,100	MAPP		W	OTP, MPC
29	Southern Indiana Gas & Electric Co. - Vectren	SIGE	Yes	2	Yes	1,888	ECAR	C		SIGE
30	Southern Illinois Power Cooperative	SIPC	Yes	1	Yes	255	MAIN	C		SIPC
31	Southern Minnesota Municipal Power Agency	SMP	No		Yes		MAPP		W	SMP
Future	SaskPower Grid Control Centre	SPC	No		No		MAPP			SPC
32	Upper Peninsula Power Co.	UPPC	Yes	4	Yes	144	MAIN	E		ATC
33	Western Area Power Administration – UGPR	WAUE	No		Yes		MAPP		W	WAUE
34	Wisconsin Energy Corporation	WEC	Yes	5	Yes	6,636	MAIN	E		ATC
35	Aquila Networks– Western Plains East Kansas	WPEK	No		Yes		SPP		W	WPEK
36	Wisconsin Public Service Corporation	WPS	Yes	4	Yes	2,641	MAIN	E		ATC
37	Montana-Dakota Utilities (Note 2)	MDU	Yes	1	Yes	465	MAPP		W	MDU

Note 1: DECO and CONS (both within MECS) are treated as individual BAs for purposes of the Energy Markets. DECO and CONS are assigned separate Estimated Peak Demand values (DECO = 12,882 MW) (CONS = 10,668 MW).
Note 2: MDU is a pseudo Balancing Authority under the Midwest ISO.
Note 3: E = East C = Central W = West
Note 4: The number in this column represents the BA configuration type described in Exhibit 2-10 of this BPM.
Note 5: The number in this column represents the Estimated Peak Demand from the NERC 2005 CPS2 Bounds Report. The value for DEVI is the Installed Capacity from the same NERC Report.

The capacity value of wind can be imputed from two different series of program runs. In the first series, wind is ignored, and the program computes the LOLP for different load levels which surround the predicted peak value for the year. In the second series, wind is added as a load modifier. The effect is that the "curve" from the first series of runs is shifted rightward (Figure 13). The difference between the load which can be served at the target reliability level for the cases with and without wind generation is assigned as the "Effective Load-Carrying Capability" (ELCC) of wind generation, i.e. the capacity value.

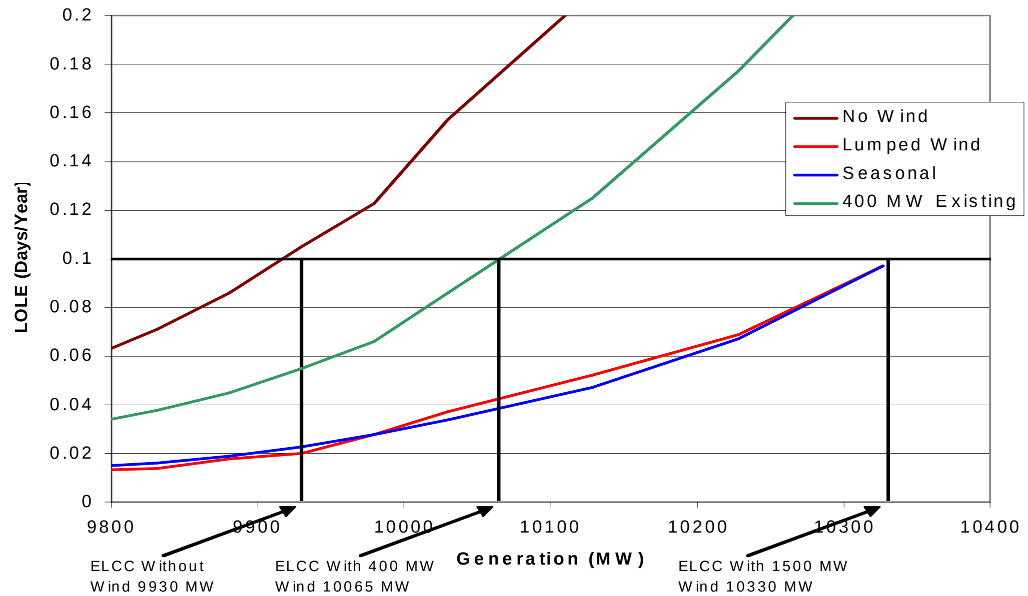


Figure 13: Determining wind generation capacity value by LOLP analysis.

MISO uses a program called "Marelli" from New Energy Associates (makers of PROMOD) to conduct reliability studies. This program runs from the PowerBase data sets, which also drive the PROMOD analysis. The version of the PowerBase data used for the PROMOD analysis in this study was input to Marelli, and an analysis similar to the described previously was conducted.

Operating Impacts

Relative to conventional generating resources, wind generation is more variable and unpredictable. The general objectives in the area of operating impacts are to assess the effects of these attributes on the operation of the power system in Minnesota and to quantify the costs related to their management.

Operation of the power system in the short-term can be broken down into two phases: Planning for the day or days to come, then operating the system in real time as load varies continuously through the hours and over its daily cycles.

For study participants, the start-up of the MISO wholesale energy markets has supplanted or modified the traditional practices by which these operating functions had been performed. The MISO Day-Ahead market is the framework against which generating units are committed for operation and scheduled. In real-time, the MISO Coordinated Reliability Dispatch and Control interacts with each of the control areas in the footprint on a nearly continuous basis to keep demand and supply in appropriate balance. Assessing the impacts of wind generation on the operation of the power system in Minnesota, then, must be done against this backdrop.

Hourly Analysis

The analysis in this project segregates power system operations into two time frames – what happens inside the hour at time intervals as small as tens of seconds, and over multiple hours, days, out to a year. Hour-by-hour analysis is a common time interval for power system studies where it is necessary to evaluate a wide range of power system conditions and capture both daily and seasonal effects. MISO utilizes a computer tool called PROMOD for this type of analysis. PROMOD contains representation of loads, transmission lines, and generating units. For the hourly load data provided as input, PROMOD determines the optimum plan for meeting the load while honoring constraints for the system (e.g. reserves, emissions, etc.) individual generating units, and the transmission network.

PROMOD can also be used to estimate locational marginal prices (LMP), since the cost functions and loading level of each generator in the optimized solution are known.

Intra-Hourly Analysis

The hour-by-hour simulation in PROMOD assumes that load, wind, and generation are "flat" for each hour. In reality, load (and wind) is continuously varying, and provisions must be made by system operators for adjustments so that demand and supply are closely matched at all times.

An approach that has been used in previous studies for estimating the impact of wind generation on requirements for regulation, load following, and other reserve impacts is based on analysis of high resolution chronological wind and load data sets. Various statistical metrics that quantify variability are first computed for the load data alone. Wind data is then combined with load data, and new metrics are calculated. The changes in these quantities are directly attributable to wind generation.

Assessing the costs of these inside-the hour impacts has been done in a variety of ways. Direct costs, for example, can be computed for incremental regulation capacity if there is a regulation market or capacity cost that can be identified. However, if the incremental requirements for the various operating reserves are brought into the hourly analysis, much of the cost impact, especially those that are associated with opportunity cost, are accrued. A good example would be where regulation and load following is performed with relatively inexpensive units. The capacity that must be held back to provide ancillary services cannot be used to serve load and generate revenue. There is, therefore, an "opportunity" cost that comes with providing ancillary services from these units. The hourly modeling will accrue these costs since other resources must be used to meet the load.

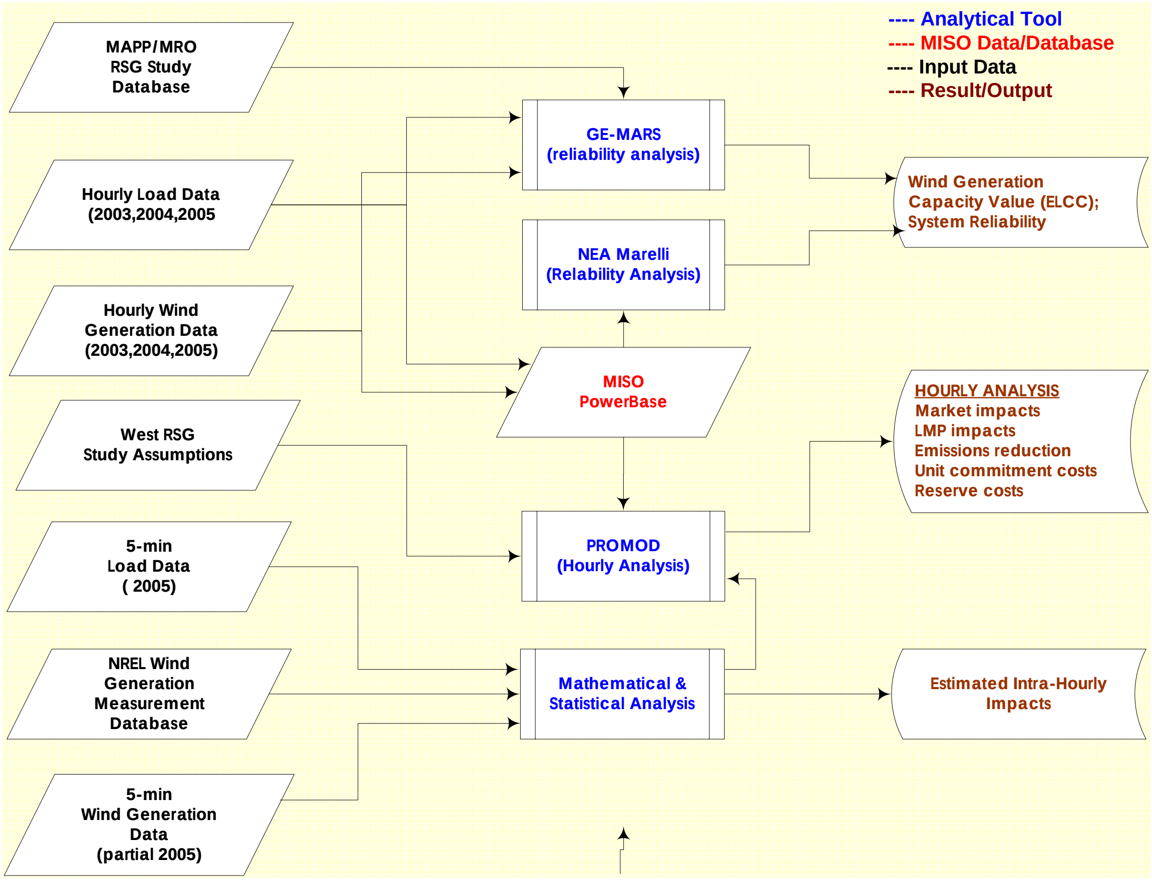


Figure 14: Flowchart for Technical Analysis

STUDY DATA AND ASSUMPTIONS

The MISO market and reliability footprints are comprised of thousands of individual generating units, many tens of thousands of megawatts of load, and many thousands of miles of transmission lines at or above 115 kV. Given the influence of the MISO energy market on the daily operations of the Minnesota companies, along with the geographical expanse of the wind generation to be considered, computer models to simulate generation scheduling and operations across the state of Minnesota must also be large.

MISO maintains large databases and computer models of network, load, and generator information to conduct a variety of regional studies. Some of these models cover the entire Eastern Interconnection (roughly all of the U.S. power system east of the Rocky Mountains). Others limit the detail to all or parts of the MISO footprint, and are used for transmission expansion planning studies.

For purposes of this study, the smaller models which represent a portion of the MISO footprint are most appropriate considering the level of detail desired.

Transmission issues for wind generation are not within the scope of this study. However, transmission capacity has a direct influence on the function of the wholesale energy market, as transmission losses and congestion are responsible for the differences in prices across the market footprint. An existing MISO planning model for PROMOD was selected as the starting point for this study. Figure 15 illustrates the scope of this West Regional Study Group (RSG) model created to encompass a number of separate transmission planning efforts so that they could be studied simultaneously.

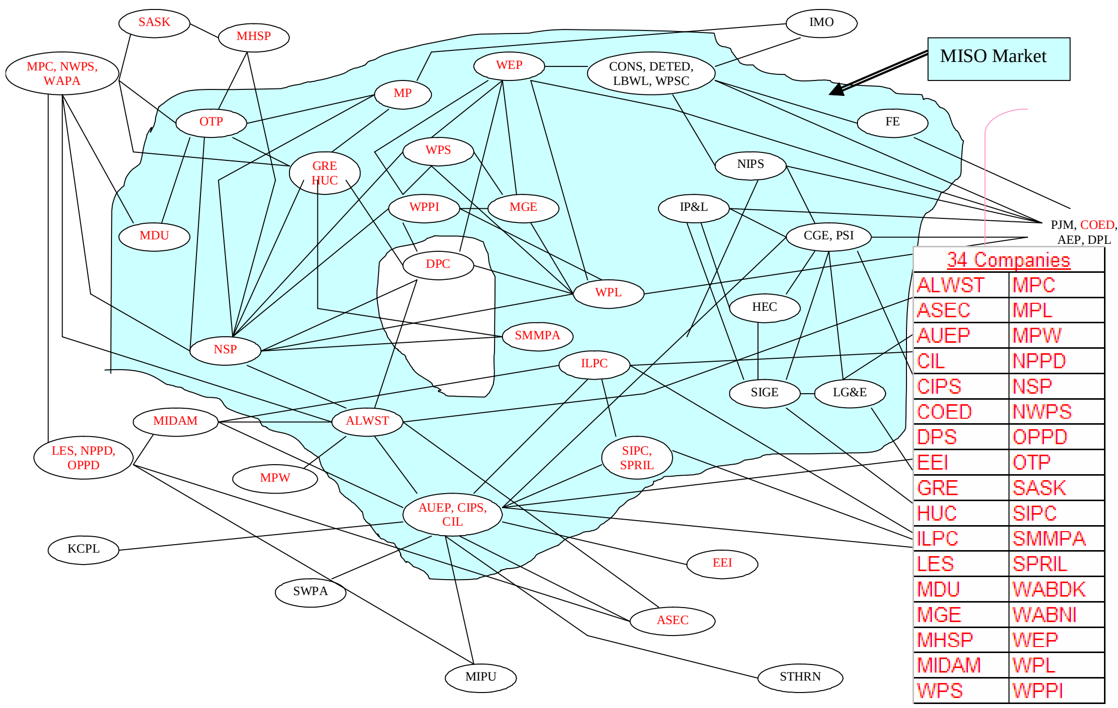


Figure 15: Overview of West RSG study PROMOD model, used as the basis for this study. Companies shown in red are represented in detail.

The transmission and non-wind generation expansion assumptions in the MISO West RSG model were used because this study is focused on the reliability and operating impacts of wind generation and is not intended to be a transmission plan or an integrated resource plan. The wind generation in the RSG model was removed and replaced with the wind scenarios developed for this study. The makeup of the West RSG PROMOD model and assumptions underlying it are detailed in Appendix A

The size and makeup of an individual control area has a significant influence on its ability to manage wind generation. Currently there are several major control areas, or Balancing Authorities (BAs), in the state of Minnesota. MISO is currently well underway with the development of an Ancillary Services Market which will result consolidation of certain BA functions. This consolidation will decrease the aggregate amount of certain ancillary services.

Most of the transmission expansion in the model adapted for this study consists of additions to the existing EHV (extra high voltage, 345 kV or higher) network. The wind generation developed for the study is “injected” at EHV buses. This assumption is used by MISO in other studies where focus is on the larger picture, and bolstering of lower voltage transmission infrastructure is not part of the study scope. The underlying local and regional transmission infrastructure was not analyzed in this study

Because the study year is more than a decade into the future, and the move toward functional consolidation of Balancing Authorities is already underway, the Minnesota companies will be considered as a single BA for the study. This could actually be a conservative assumption if after consolidation of BA's in the MISO footprint the resulting regional BA is larger than Minnesota.

The PROMOD West RSG model, with the wind generation scenarios developed for this study, is used to represent the MISO energy market operations. It is assumed that this cost-based approach will adequately reflect the function of the day-ahead and real-time markets.

Modeling Minnesota Electric Load in 2020

Table 8 documents the retail sales statistics upon which the Minnesota study is premised. The total retail sales for 2004 were 61,965 GWH. Assuming a 2.0% annual growth rate, retail sales in 2020 are projected to be 85,093 GWH.

Table 8: Minnesota retail sales by company for CY2004 and Total Retail Sales assumptions for study

	2004 MN Retail Sales in kWh[1]	
Investor-Owned Utilities		
Xcel	30,559,280,490	49.3%
MP	8,580,900,000	13.8%
OTP	1,957,456,566	3.2%
IPL	841,511,856	1.4%
NWEC	524,992	0.0%
TOTAL IOU	41,939,673,904	67.7%
Cooperative Utilites		
GRE	10,408,968,000	16.8%
Minnkota	1,808,326,904	2.9%
Dairyland	737,462,789	1.2%
Basin	751,736,085	1.2%
TOTAL COOP	13,706,493,778	22.1%
Municipal Utilities		
SMMPA	2,714,070,325	4.4%
MRES	805,570,000	1.3%
MMPA	2,302,721,000	3.7%
CMMPA	516,974,120	0.8%
TOTAL MUNI	6,339,335,445	10.2%
TOTAL ALL	61,985,503,127	100.0%

[1] July 1, 2003 to June 30, 2004 (MN DOC 1/15/05)

Retail Sales Annual Growth Rate	Wind Percent Retail Sales	Wind Annual Capacity Factor		2004	2011	2020
1.0%			MN Retail Sales (GWh)	61,986	66,457	72,683
	15%	40%	Nameplate wind (MW)	2,653	2,845	3,111
	20%	35%		4,043	4,335	4,741
	20%	40%		3,538	3,793	4,149
	25%	40%		4,422	4,741	5,186
2.0%			MN Retail Sales (GWh)	61,986	71,202	85,093
	15%	**40%**	Nameplate wind (MW)	2,653	**3,048**	**3,643**
	20%	35%		4,043	4,645	5,551
	20%	**40%**		3,538	**4,064**	**4,857**
	25%	**40%**		4,422	**5,080**	**6,071**

Table 9 shows the loads from the West RSG PROMOD case for 2020. The highlighted (in yellow) companies are those having significant Minnesota load. The aggregated load, however, for these companies is 142,177 GWH, well in excess of the study projections for 2020.

Table 9: Loads by Company from PROMOD West RSG case for 2020.

Company	Load (MWH)
ASEC	21195998
GRE	19677281
MDU	2807994
MPC	7048485
NWPS	1679993
OTP	6843984
WABDK	4445004
ALWST	19728132
AUEP	43335000
MHSP	24793994
SASK	20286020
DPC	6675034
HUC	408002
MPL	12674090
NSP	67017594
SMMP	2512775
LES	4328000
MIDAM	25180996
MPW	1133011
NPPD	14662941
OPPD	12225999
WABNI	16423007
COED	112141254
CIL	7101042
CIPS	20675055
EEI	4322030
ILPC	18021032
SIPC	2019994
SPRIL	2270002
MGE	4038000
WEP	37665970
WPL	16316931
WPPI	6069003
WPS	15090049

A simple algorithm for extracting the Minnesota load from the PROMOD was utilized. From the work scope, the aggregated retail sales of five entities – Xcel Energy, Minnesota Power, Ottertail Power , Great River Energy, and SMMPA comprise 87.5% of Minnesota retail electricity sales. And, from 2004 data provided by MISO, it can be computed that the Minnesota portion of the Xcel-NSP load comprises 67% of their company load in MISO. Adjusting for the out-of-Minnesota sales for Xcel Energy, the load for these five entities from the PROMOD results is 86610 GWH.

To account for the other Minnesota companies listed in the table from the statement of work but not explicitly accounted for in the extraction from the PROMOD results, the aggregate load for the five companies is divided by 87.5%, yielding an estimated Minnesota state load of 98,983 GWH.

The PROMOD load is not “retail sales” as it is comprised of the energy transported to high voltage delivery points (substations). Losses in the distribution system are estimated to be about 7%. Applying this factor to the PROMOD load to estimate “retail sales” at customer metering points yields estimated Minnesota retail sales of 92,054 GWH.

From information exchanged with MISO, it was confirmed that an average growth rate of 2.5% was assumed for scaling loads for the 2020 West RSG PROMOD case. The number above is almost identical to the 2004 Minnesota retail sales escalated at 2.5% annual growth to 2020. It appears, therefore, that the simple algorithm proposed does a good job in estimating Minnesota retail sales from the PROMOD data.

A consequence of the PROMOD loads in the 2020 West RSG case is that the wind generation data provided earlier amounts to slightly less than the target energy penetration levels due to slightly increased retail sales. After discussions, it was decided that the most straightforward way to compensate would be to increase the wind generation slightly. This was accomplished by increasing the installed capacity numbers by a factor equal to 92,054/86,610, or 1.063.

Correlated hourly wind generation and load data is a foundation for the hourly analysis in this study. Because wind generation and electric demand are both affected by the regional meteorology, it is important to preserve the correlations that might exist between these data sets. As previously described, chronological wind speed and generation data profiles were developed at five minute intervals for the historical years 2003, 2004, and 2005. To create the load data corresponding to these years, hourly load data from these years for the Minnesota companies was retrieved from archives and scaled per the discussion above to create load data for the study. CY2004 was selected as the “base” year in that it was modified to achieve the target annual retail electric sales. The ratio between the new peak hourly load for the 2020 data and the peak load for the historical 2004 load data was then applied to load data from 2003 and 2005.

Developing Wind Generation Data

The basic approach for developing wind generation profiles is to apply a “power curve” from a commercial wind turbine to the wind speed values at each five-minute interval. With 152 observation points in the MM5 model and up to 6000 MW of wind generation potentially required in the model, each wind speed observation must represent more than a single turbine.

Appendix C describes the approach used for this study, which approximates spatial diversity, terrain, and turbine shadowing effects by adjusting raw wind speed values at high resolution before calculating power (Figure 16). Wind speed data at five-minute intervals over three consecutive calendar years across 152 separate locations across Minnesota and the eastern half of the Dakotas was processed to yield five-minute and hourly wind generation data for each of the scenarios.

In an earlier section and in the companion report, it was noted that net capacity factors were calculated by assuming a constant loss factor of 14%. The wind generation data calculated from the method described in the appendix makes no such assumption, as the effective plant power curve takes those factors which contribute to the losses into account.

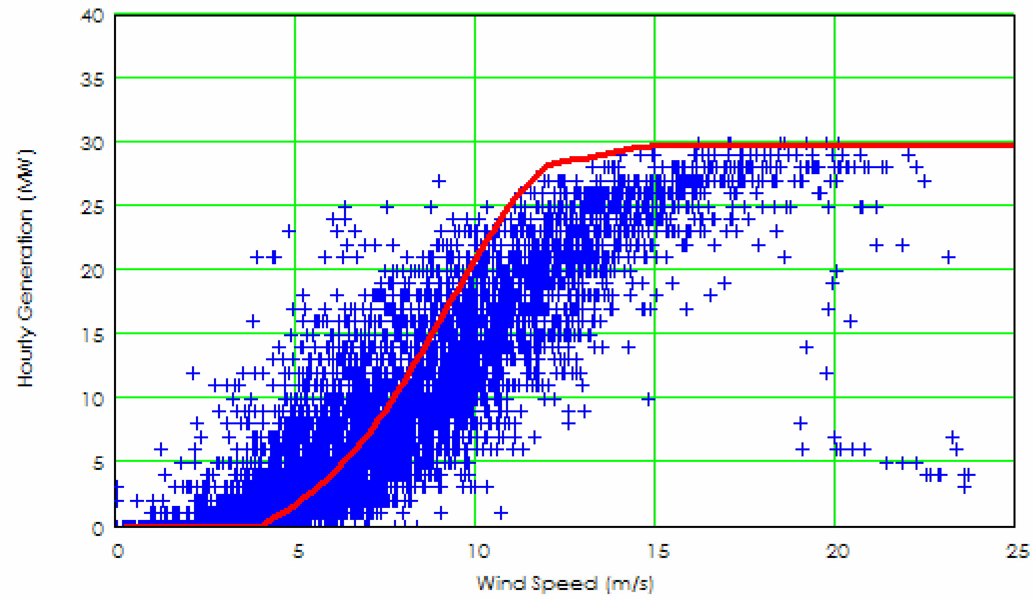


Figure 16: Single turbine versus "plant" power curves, from empirical data for 30 MW plant

For use in the hourly PROMOD model, it was necessary to identify the network buses into which the wind generation would be injected. As described previously, EHV buses were selected to avoid local transmission issues. Figure 17 illustrates 14 zones that were created to collect the wind energy. Information about each of these zones is found in Table 10.

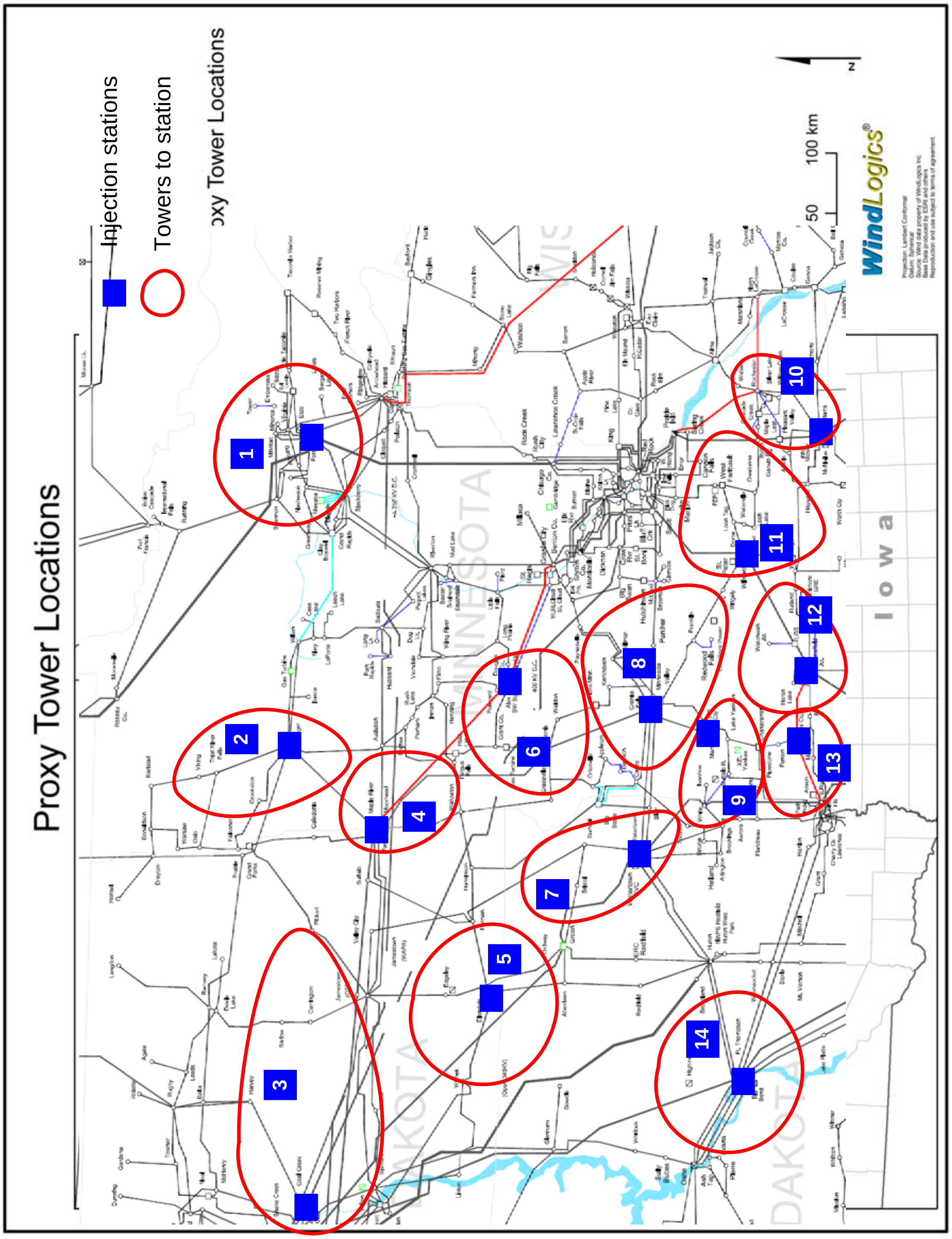


Figure 17: Wind generation regions and network injection buses

Table 10: Meteorological Tower Assignments by Region and Scenario

Area	Bus	Voltage	Towers	MW – 15%	MW – 20%	MW – 25%
1	Forbes	500 kV	79, 80, 81, 82, 83, 84, 85	200	280	289
2	Winger	230 kV	63, 64, 133, 134, 138, 142, 143	200	280	280
3	Leland	345 kV	113, 114, 115, 116, 117, 123, 124, 125	280	320	320
4	Maple River	345 kV	2, 3, 91, 92, 126, 140, 141	240	280	280
5	Ellendale	230 kV	111, 112, 118, 119, 120, 121, 122	261	261	280
6	Alexandria	345 kV	10, 13, 65, 68, 88, 89, 127, 146, 147, 148	280	400	400
7	Watertown	345 kV	98, 99, 100, 101, 102, 103, 104, 105, 106, 109, 110	0	200	440
8	Granite Falls	345 kV	75, 78, 128, 129, 131, 135, 136, 137, 145, 150	360	400	400
9	Lyon County	345 kV	21, 22, 23, 24, 25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 50, 51, 52, 53, 54, 55, 67, 68, 69, 70, 71, 72, 73, 74, 93, 94, 95, 96, 97	607	767	1364
10	Adams	345 kV	38, 39, 40, 41, 42, 43, 44, 45, 139, 151	364	404	404
11	Willmarth	345 kV	8, 9, 11, 12, 86, 87, 130, 132, 144, 149, 152	283	443	443
12	Lakefield Jct.	345 kV	1, 4, 5, 6, 7, 14, 15, 16, 17, 18, 19, 20, 36, 37, 90	432	552	600
13	Nobles Co.	345 kV	46, 47, 48, 49, 56, 57, 58, 59, 60, 61, 62, 76, 77	127	207	520
14	Ft. Thompson	230 kV	107, 108	40	80	80
	Total			3674	4874	6091

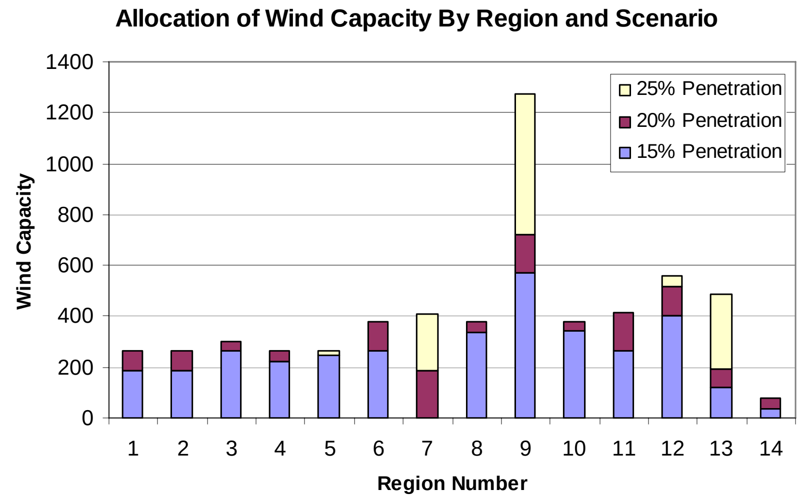


Figure 18: Installed wind generation capacity by region and scenario

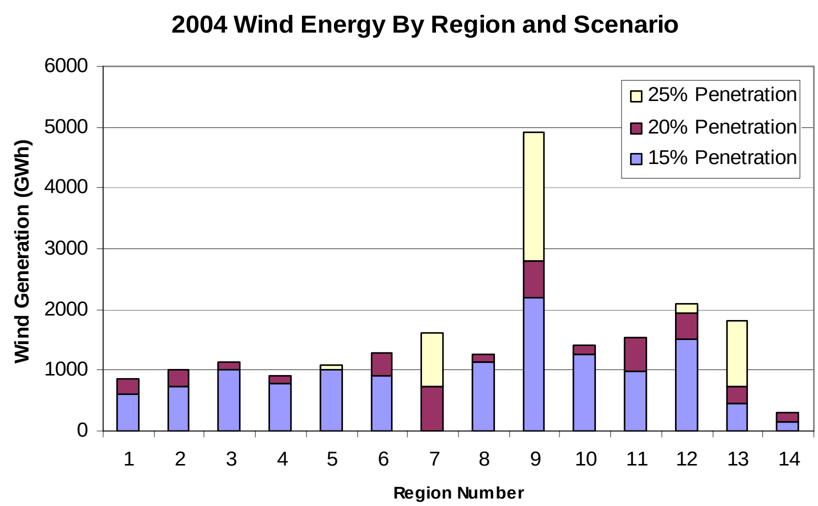


Figure 19: Wind energy production by region and scenario.

Table 11: Installed Capacity by Region and Penetration Scenario

Adjusted Assignments of 2004 Wind Scenario Rationalized With MN 2004 Load Escalated to 2020

	Region 1	Region 2	Region 3	Region 4	Region 5	Region 6	Region 7	Region 8	Region 9	Region 10	Region 11	Region 12	Region 13	Region 14	Total
2004 15%	187	187	262	225	244	262	0	337	569	341	265	405	119	37	**3441**
2004 20%	263	263	301	263	245	376	188	376	721	380	417	519	195	75	**4582**
2004 25%	262	262	299	262	262	374	411	374	1274	377	414	560	486	75	**5689**

Table 12: Adjustment of Wind Generation Model to Achieve Study Target Penetrations

Target Energy Penetration	Derived Scale Factor	Wind Energy (GWh)	Actual Penetration (Energy)
15%	0.937	12715	14.97%
20%	0.940	16953	19.96%
25%	0.934	21192	24.95%
Target Retail Sales of 84922 GWh (based on 2004 adjusted 4 BA Loads)			

Table 13: Characteristics of Wind Generation Model – Capacity Factor by Season & Region

	Regions					
	Dakotas	Buffalo Ridge	Central Minnesota	North Minnesota	South Minnesota	Total
`Winter	38.7%	43.9%	35.8%	32.7%	40.3%	39.2%
Spring	39.2%	43.3%	42.3%	40.6%	42.4%	42.1%
Summer	36.7%	40.1%	36.5%	38.8%	35.0%	37.8%
Autumn	45.8%	54.9%	48.2%	46.3%	51.1%	50.9%
Year	40.1%	45.6%	40.7%	39.6%	42.2%	42.7%

ESTIMATING RESERVE AND OTHER OPERATIONAL REQUIREMENTS

Consideration of the controllable resources required to balance the control area and maintain security in PROMOD is handled by the "total operating reserve" setting for the balancing authority. The program will assure that this amount of capacity is available each hour and is not being used to serve load. This has the effect of extending the resource "stack", and likely commits some more expensive resources.

For the MN balancing authority considered in this study, there are several categories of reserves:

- **Regulating** – capacity that can be adjusted up or down to maintain balance between control area demand and supply.
- **Spinning** – The extra amount of on-line generation capacity that must be carried to cover the largest contingency in the reserve sharing pool.
- **Non-Spinning** – an additional amount of generation that can be brought on-line in a short period of time to cover the largest contingency.
- **Load Following** – Capacity that can be adjusted up or down to follow the trend in the control area demand. This capacity will be economically dispatched at frequent intervals, and may include both generation participating in the MISO real-time market as well as regulating reserves.

The baseline MISO assumption of 5% total operating reserves is larger than can be accounted for by summing the categories listed above. In the context of significant wind generation, this will include an amount of capacity to cover deviations from forecast conditions in the coming hour or hours. Such deviations would result from errors in short-term hourly load forecasts, for example. With significant amounts of wind generation in the control area, these additional reserves would be carried by operators to cover drops in wind generation over the next hour with respect to a persistence forecast.

Regulating Reserves

Control area regulation is a capacity function. Compensation for load changes or deviations over very short time frames (tens of seconds to minutes) is provided by units capable of the necessary response rates and operating on Automatic Generation Control (AGC). As the size of a balancing authority increases, the regulation requirement as a fraction of the peak load generally declines. Such a relationship is depicted in Figure 20. This graph is based on conversations with operations personnel from MISO.

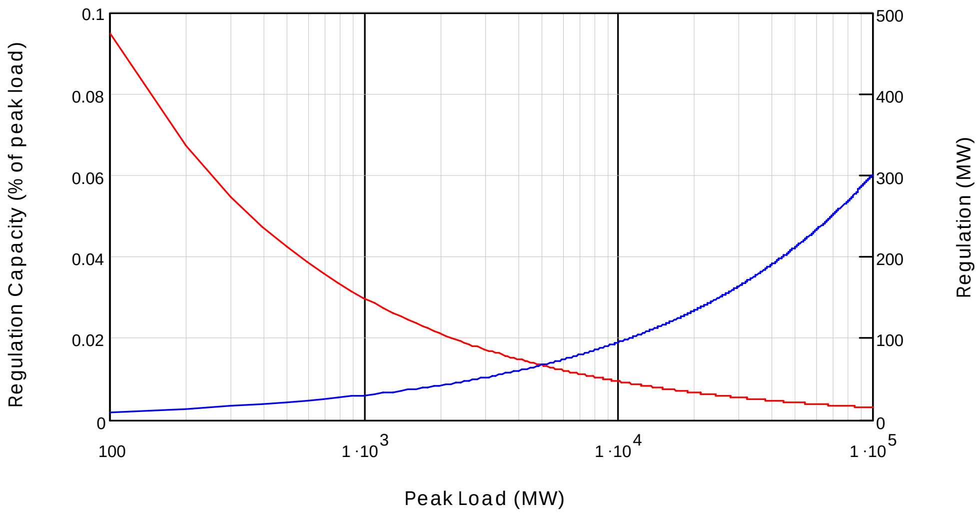


Figure 20: Approximate regulating requirements for a Balancing Authority as a function of peak demand.

Using the relationship from Figure 20, regulation requirements for the existing Minnesota balancing authorities and the combined balancing authority in 2020 can be estimated. These are shown in Table 14. The effect of balancing authority functional consolidation is quite pronounced with regard to regulation requirements.

Table 14: Estimated Regulating Requirements for Individual MN Balancing Authorities and Aggregate

Balancing Authority	Peak Load	Regulating Requirement (from chart)	Regulating Requirement (% of peak)
GRE	3443 MW	56 MW	1.617%
MP	2564 MW	48 MW	1.874%
NSP	12091 MW	104 MW	0.863%
OTP	2886 MW	51 MW	1.766%
Sum of Regulating Capacity		**259 MW**	
Combined	20984 MW	**137 MW**	**0.655%**

Fast changes in wind generation can increase the amount of regulation capacity required. Many previous studies have shown this impact to be quite modest, especially where the number of individual wind turbines relative to the system peak load is very high. The National Renewable Energy Laboratory (NREL) has been collecting high resolution data from operating wind plants for a number of years. Extensive analysis has been performed on this data that has contributed to the understanding of wind plant production variations on all operating time frames. Using the NREL measurement data, output fluctuations on the regulation time frame from a large wind plant are shown to be less than one or two percent of the plant nameplate rating (Figure 21).

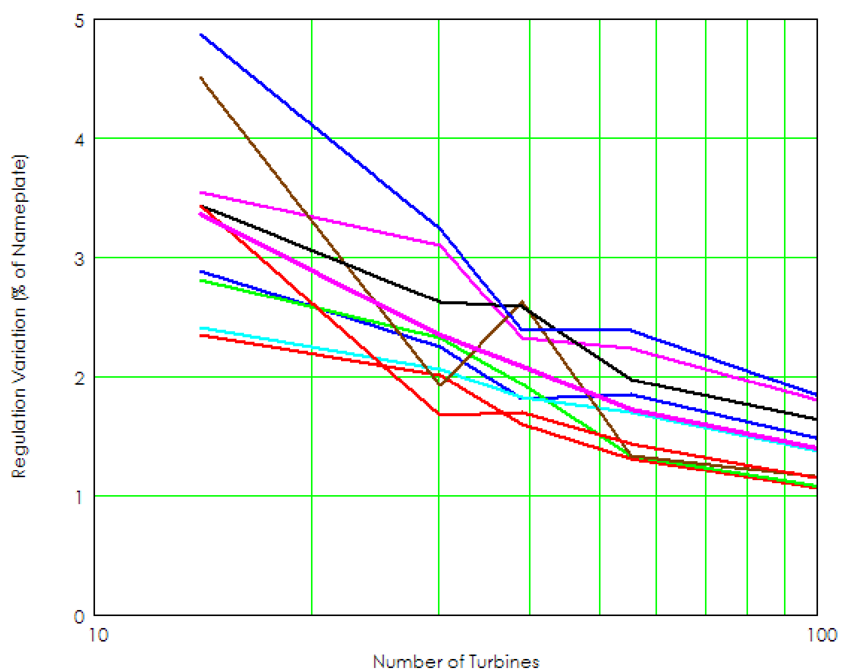


Figure 21: Variation of the standard deviation of the regulation characteristic for each of nine sample days by number of turbines comprising measurement group.

Using a conservative estimate of 2 MW for each 100 MW of wind generation in the scenarios for this study, the regulation requirement for the combined MN balancing authority with the prescribed amounts of wind generation can be computed. By assuming that the regulation variations between each wind plant and the load are uncorrelated, the regulation requirement for the load and wind combination is computed with the following formula:

$$\text{New\_Regulating\_Requirement} := k\sqrt{\sigma_{Load}^{2} + N\cdot\left(\sigma_{w100}^{2}\right)}$$

Where

- k = a factor relating regulation capacity requirement to the standard deviation of the regulation variations; assumed to be 5
- σ_{Load} = standard deviation of regulation variations from the load
- σ_{w100} = standard deviation of the regulation variations from a 100 MW wind plant
- N = wind generation capacity in the scenario divided by 100

Results of this computation for the three wind generation scenarios are shown in Table 15.

Table 15: Estimated Regulation Requirement for MN Balancing Authority in 2020

Scenario	Regulation Capacity Requirement
Base	137 MW
15% Wind Generation	149 MW
20% Wind Generation	153 MW
25% Wind Generation	157 MW

Contingency Reserves

The present reserve obligation for the Minnesota balancing authorities and companies is defined by the rules of the MAPP Generation Reserve Sharing Pool. The largest contingency which defines the pool's reserve requirement is the loss of 1500 MW important from Manitoba on a 500 kV transmission line.

In the scenario defined for the study, the reserve obligation of the Minnesota utilities is projected to remain unchanged because:

- Loss of the Manitoba import is still assumed to be the largest single contingency
- The share of load in the reserve sharing pool, and the end-use load obligation (EULO) ratio of the Minnesota utilities to the larger pool is also assumed to remain the same.

Consequently, the Minnesota balancing authority would be required to carry 660 MW of reserve, of which 330 MW is spinning and 330 MW is quick-start.

Note: After this study was well underway, the consolidation of the MAPP Generation Reserve Sharing Pool into a new, larger entity that largely encompasses the MISO Reliability Footprint was announced. The Midwest Contingency Reserve Sharing Group filed its participation agreement with the Federal Energy Regulatory commission in the fall of 2006. Beginning January 1, 2007, the Midwest contingency Reserve Sharing Group is scheduled to commence operations and is anticipated to reduce the contingency reserve obligation of the Minnesota utilities.

Load Following

Within the hour, enough generation must be available to compensate for the underlying trends in the load beyond the fast regulation time frame. In MISO, load trends are accommodated by a combination of the real-time market and regulation capability. Either response cannot be directly considered in the PROMOD hourly analysis. Therefore, no distinction will be made, and the effects of wind generation will be gauged from analysis of load and wind time series data alone.

Figure 22 through Figure 24 depict the distributions of absolute changes over a five-minute interval for load and load net wind generation. The effect of wind generation on these changes is relatively modest, owing to the significant geographic diversity present in the wind scenarios.

Additional amounts of generic reserve can be estimated as some multiple of the standard deviations. As shown in Table 16, two standard deviations, which would encompass over 95% of all variations in the sample, was assumed. This assumption is consistent with operational practice for power systems. The metric by which control over periods of ten minutes is judged, CPS2 (Control Performance Standard 2) requires that the difference between load and generation over a ten-minute period must be smaller than a specified limit for 90% or more of the ten-minute intervals over the month. Consequently, not all deviations in the control area demand are fully compensated, as CPS2 scores for existing control areas vary across the range from 90 to 100%.

Table 16: Summary of Five-minute Variability

Scenario	Standard Deviation of 5-minute changes
Base	50 MW
15% Wind Generation	55 MW
20% Wind Generation	57 MW
25% Wind Generation	62 MW

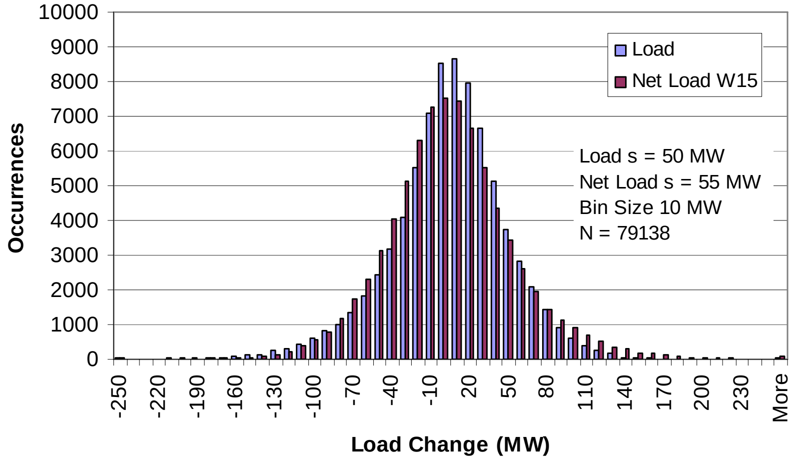


Figure 22: Five-minute variability – 15% wind generation

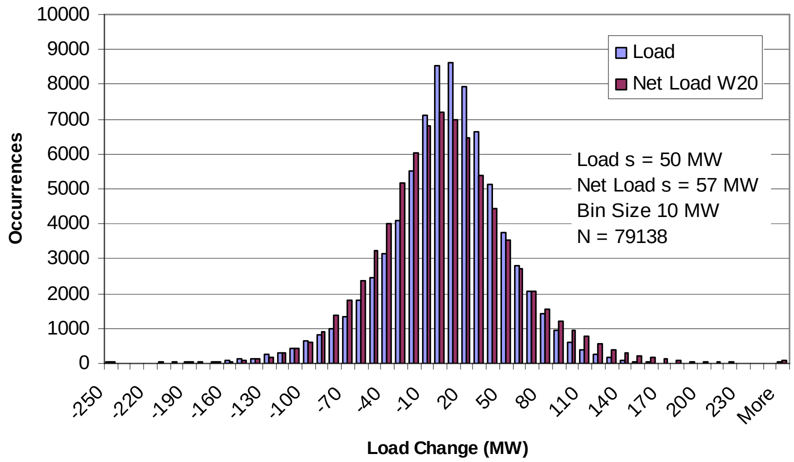


Figure 23: Five-minute variability – 20% wind generation

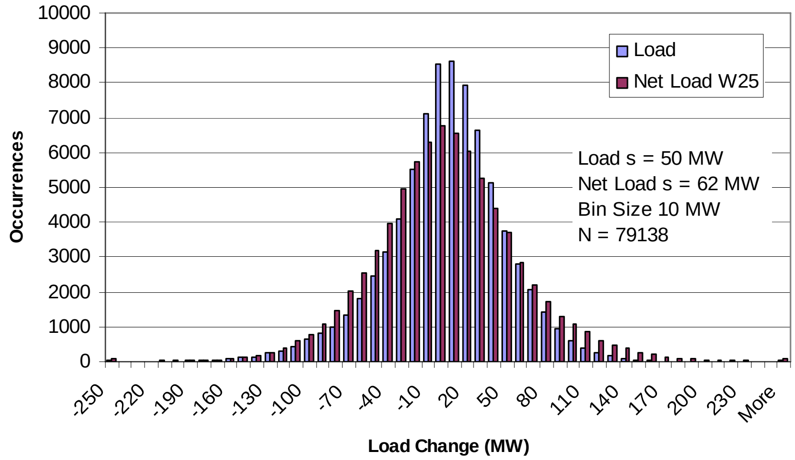


Figure 24: Five-minute variability – 25% wind generation

Operating Reserve “Margin"

The size and geographic diversity of the wind generation scenarios constructed for the study move the significant variability and uncertainty related to wind generation out to time frames ranging from one to several hours. Table 17 illustrates the standard deviation of the next-hour wind generation from a persistence forecast, which is a likely method for forecasting over such time frames. Distributions of next-hour errors from a persistence forecast are shown in Figure 25 through Figure 27.

The general response operationally to increased uncertainty in forward time frames is to carry additional reserves. How specifically this would be done in some optimal fashion for wind generation is not yet known. Some control area operators pad their reserves by an amount proportional to what they consider the next hour uncertainty due to load forecast to be. Within this MISO centralized dispatch structure, it is not clear how a large state-wide balancing authority would cover unexpected deviations (especially reductions) in wind generation. However, because of the size and diversity of the wind generation scenarios, nearly all of the significant impacts on variability and operational uncertainty are outside of the hour. Therefore, an operating reserve margin to cover unpredictable changes in wind generation from hour to hour is a conservative, yet reasonable approximation. For purposes of this study, additional reserve in the amount of two times the standard deviation will be assumed.

Table 17: Next-hour Deviation from Persistence Forecast by Wind Generation Scenario

Scenario	Standard Deviation of 1-hour Wind Generation Change
15% Wind Generation	155 MW
20% Wind Generation	204 MW
25% Wind Generation	269 MW

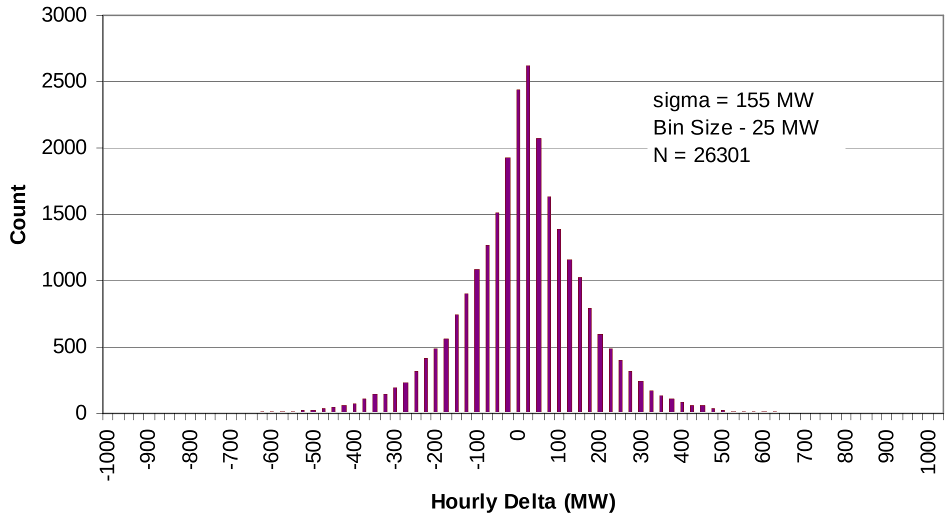


Figure 25: Next-hour deviation from persistence forecast – 15% wind generation

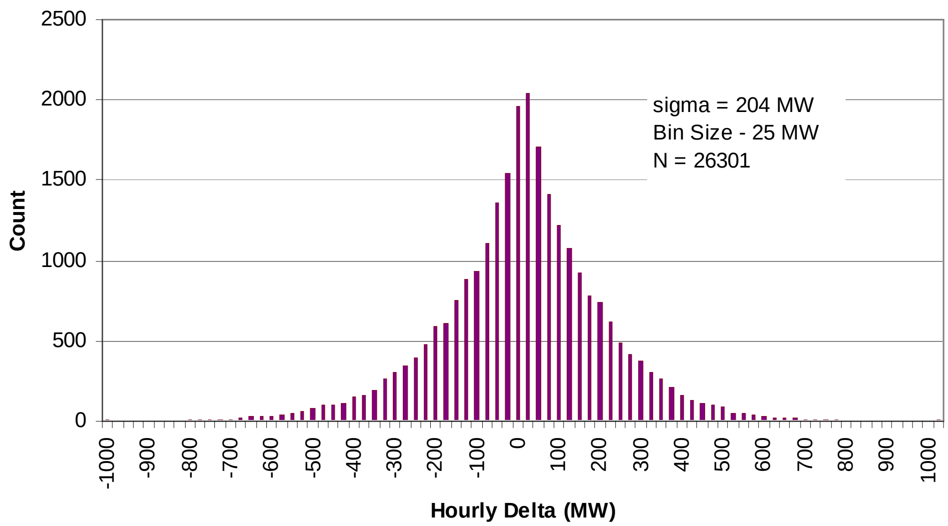


Figure 26: Next-hour deviation from persistence forecast – 20% wind generation

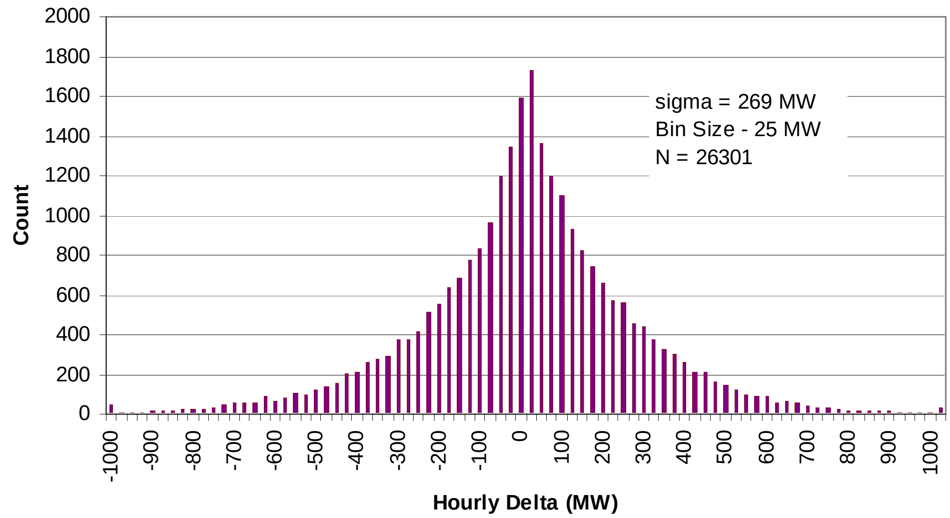


Figure 27: Next-hour deviation from persistence forecast – 25% wind generation

Analysis of the load and wind generation time series data reveals that the significant effects of wind generation on the operation of the Minnesota Balancing Authority are actually outside the hour, i.e. there are only modest impacts on time frames associated with regulation or the real-time market. Consequently, the additional amounts of reserve capacity for these services would also be modest.

Based on the assumptions discussed with the TRC, the spinning and non-spinning reserve requirements for the Minnesota balancing authorities and companies would not be affected by the presumed consolidation into a single balancing authority.

Covering unanticipated changes in wind generation over periods of an hour or more appears to be the area where wind generation would have the largest impact. By considering some additional amount of reserves to cover this uncertainty, and factoring in the incremental requirements from the other categories, the "Total Operating Reserve" criteria for the PROMOD studies can be developed for the three wind generations scenarios. These estimates, in MW and as a percentage of the balancing authority peak load, are shown in Table 18.

Discussion

The need for additional reserves beyond those identified for regulation and load following was discussed extensively with the TRC.

A plan for the PROMOD cases was developed to assess the degree to which reserve assumptions would affect integration costs. Cases for the 5% operating reserves roughly correspond to the situation where the "operating reserve margin" from Table 18 is zero for all wind generation scenarios (due to the fact that wind generation has only minor impacts on the within-the hour reserves from the data analysis). Three new cases for the base year of 2004 and each wind generation penetration level were run with the total operating reserves as specified in Table 18. Sensitivity cases were run around each of these three new cases where the reserve requirement 1% higher and 1% lower than the value from the table to assess the cost sensitivity to operating reserve assumptions. This sensitivity is discussed later in the report.

Table 18: Estimated Operating Reserve Requirement for MN Balancing Authority – 2020 Load

Reserve Category	Base		15% Wind		20% Wind		25% Wind	
	MW	%	MW	%	MW	%	MW	%
Regulating	137	0.65%	149	0.71%	153	0.73%	157	0.75%
Spinning	330	1.57%	330	1.57%	330	1.57%	330	1.57%
Non-Spin	330	1.57%	330	1.57%	330	1.57%	330	1.57%
Load Following	100	0.48%	110	0.52%	114	0.54%	124	0.59%
Operating Reserve Margin	152	0.73%	310	1.48%	408	1.94%	538	2.56%
Total Operating Reserves	**1049**	**5.00%**	**1229**	**5.86%**	**1335**	**6.36%**	**1479**	**7.05%**

Notes on Table:

- Assumes 2020 MN Balancing Authority peak load of 20984 MW
- Requirements for load following and reserve margin based on two standard deviations of the five-minute variability and next hour forecast error, respectively.

Modeling Time-Varying Reserve Requirements in PROMOD

PROMOD is generally capable of modeling only a constant operating reserve level for a single case. New Energy Associates provided guidance on a work-around for varying the operating reserves by hour.

A variable operating reserve level is created by introducing a fictitious generating resource that is dedicated to serving a fictitious load. The available capacity on the resource is counted toward the total operating reserves in the balancing area of interest. By varying the load served by the fictitious resource, the available capacity and hence the reserve contribution can be varied by the profile of the fictitious load.

Wind generation data for each scenario was analyzed to characterize the variability over one hour. Figure 28 shows plots of the wind generation changes over a single hour for each scenario. Of interest is the revelation that the maximum variability does not occur at maximum generation, but rather in the mid-range of the aggregate production curve.

Standard deviations for each quintile of production were computed for the samples above, and are documented in Table 19. To facilitate modeling a time-varying reserve profile, quadratic approximations to the empirical curves were developed (Figure 29). With these quadratic expressions, an hourly profile for this operating reserve margin was developed for PROMOD from the hourly wind generation data.

The time-varying reserve profile is illustrated in Figure 30 for six weeks of hourly data. The statistics of the varying reserve profile used in this study are documented in Table 20. The average value over the year is smaller than the “fixed reserve” assumption, although there are hours where there is much more reserve being carried, as evidenced by the peak values.

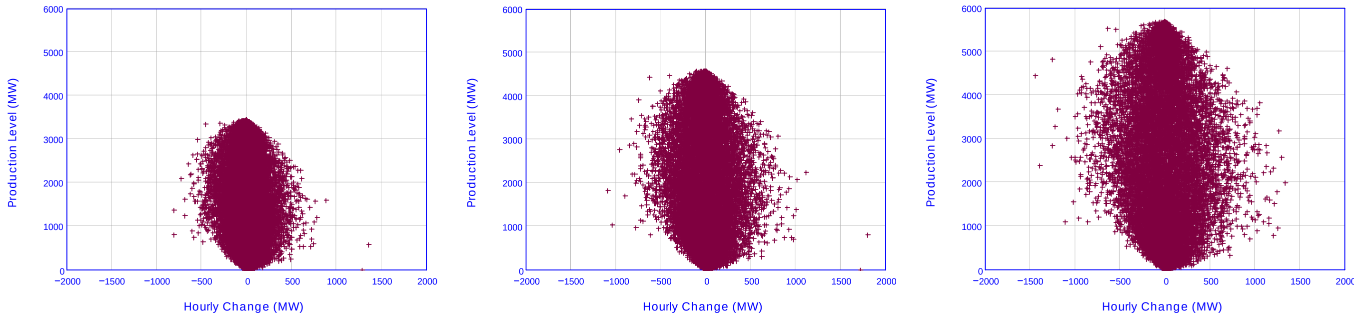
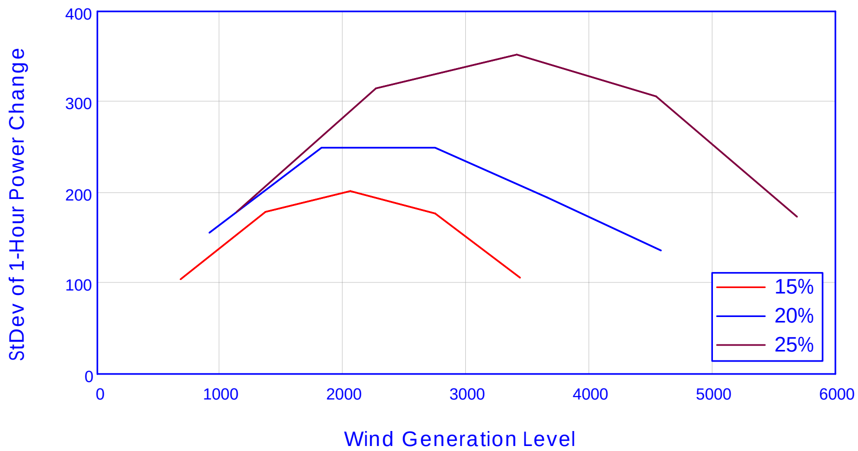
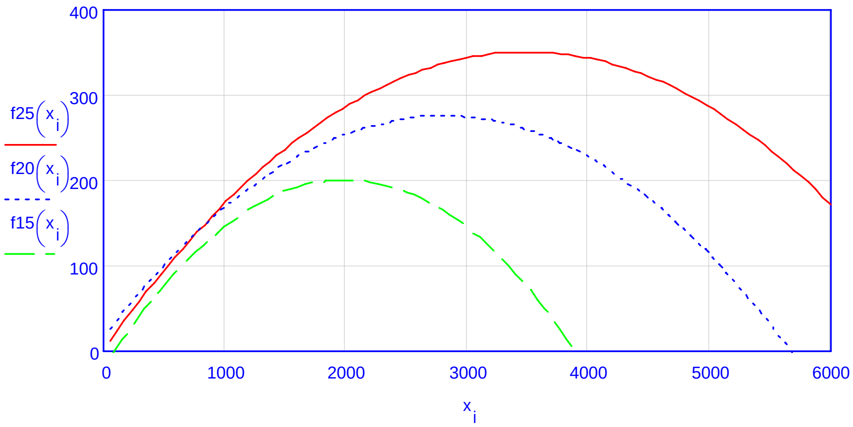


Figure 28: Hourly wind generation changes as functions of production level. 15% (left); 20% (middle); 25% (right)

Table 19: Standard Deviation of One-Hour Production Changes by Generation Level

Production Level	One Standard Deviation of 1-Hour Power Change					
	15% Wind (3441 MW)		20% Wind (4582 MW)		25% Wind (5689 MW)	
	MW	%	MW	%	MW	%
0 – 20%	103	2.88%	155	3.38%	177	3.11%
20% - 40%	178	5.11%	249	5.43%	314	5.52%
40$ - 60%	201	5.84%	249	5.43%	352	6.19%
60% - 80%	176	5.11%	194	4.23%	306	5.38%
80% - 100%	105	3.05%	135	2.95%	173	3.04%
Average	156	4.53%	205	4.47%	269	4.73%





$$f15(x) := 200 - \frac{(x - 2000)^2}{18000}$$

$$f20(x) := 275 - \frac{(x - 2800)^2}{30000}$$

$$f25(x) := 350 - 1\frac{(x - 3500)^2}{35000}$$

Figure 29: Empirical next-hour wind variability curves (top) and quadratic approximation (middle) and equations (bottom). Vertical axis quantity on charts is standard deviation.

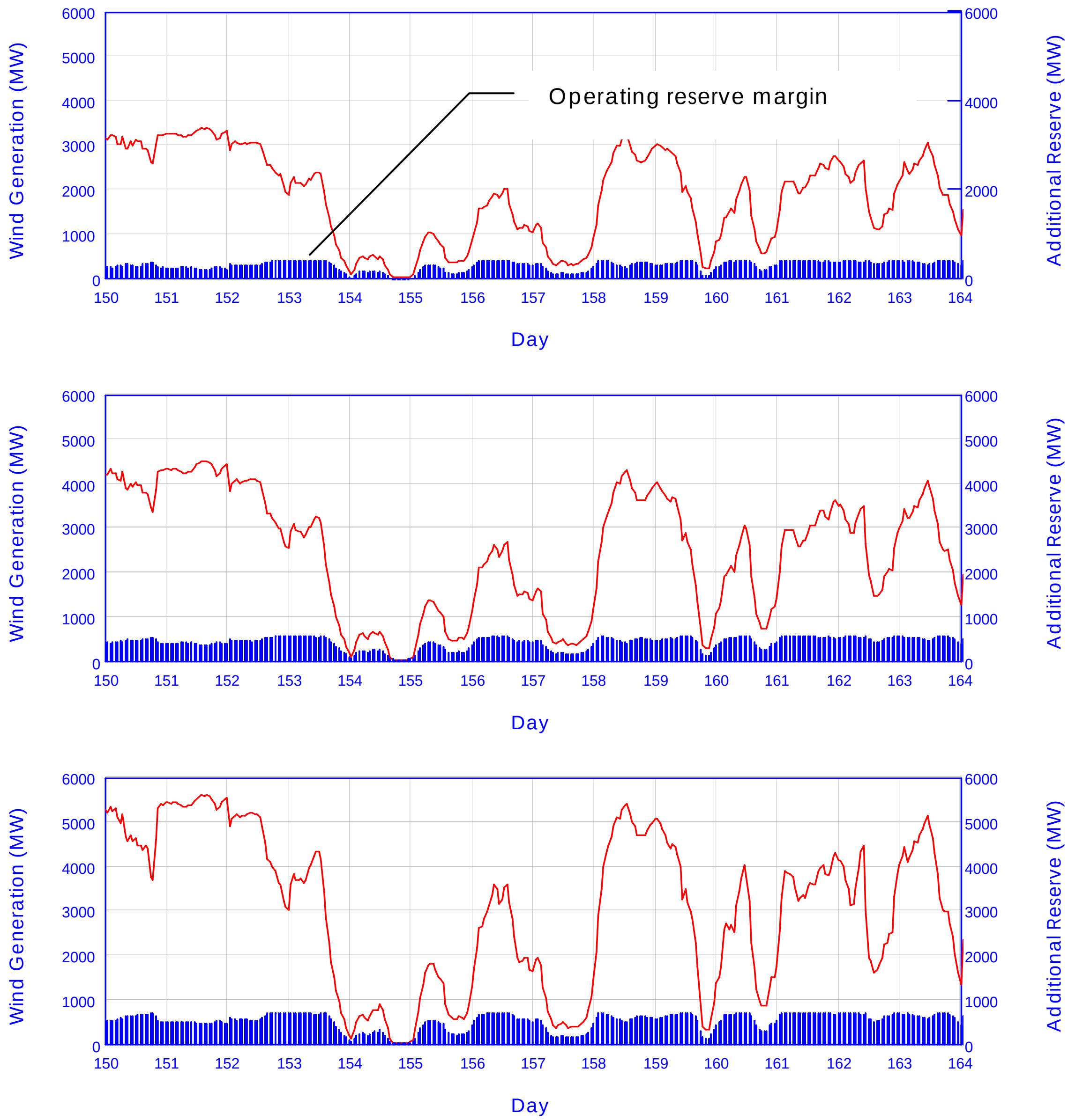


Figure 30: Illustration of time varying "operating reserve margin" developed from statistical analysis of hourly wind generation variations.

Table 20: Characteristics of Additional Variable Reserve

Characteristic	Additional Variable Reserve					
	15% Wind (3441 MW)		20% Wind (4582 MW)		25% Wind (5689 MW)	
	MW	% of System Peak	MW	% of System Peak	MW	% of System Peak
Mean	259	1.23%	384	1.83%	473	2.25%
Maximum	400	1.91%	550	2.62%	700	3.34%

Section 4

RELIABILITY IMPACTS

The goal of the reliability analysis is to determine the capacity value of wind generation at each penetration level. The reliability impacts scope from the statement of work for the project is as follows:

> Evaluate the reliability impacts of the wind generation in the planning horizon (seasonal and annual, for three years):
>
> - Determine the impact of the wind generation on regional reliability (Loss of Load Probability) and reserve capacity obligations.
> - 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; review and discuss inter-annual variations in ELCC; evaluate simplified methods of approximating ELCC.
> - Compare results to the existing MAPP guidelines for establishing capability ratings for variable capacity generation and develop recommendations for improvements to the guidelines. *Model and Input Data:*
>
> *It is anticipated that reliability impacts analysis can be developed from the GE Multi-Area Reliability Simulation (MARS) program and the associated database developed for the recent MAPP Reserve Capacity Obligation Review with both thermal and hydro resources included.*

The base model for this study was adapted from the West RSG generation and transmission expansion assumptions. The new conventional generating capacity is shown in Figure 31.

The West RSG case focuses on a 2011 study year, so the assumed loads for this study are higher.

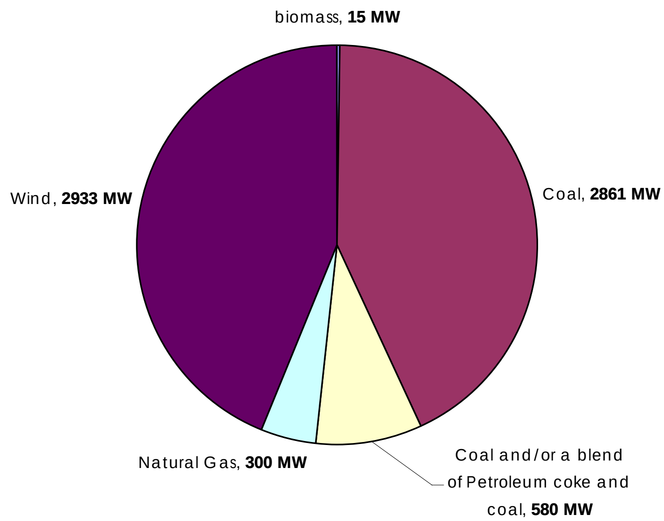


Figure 31: New conventional generation in West RSG expansion plan

An initial assessment of wind energy production during the highest system load hours is presented in Figure 32. Three years of wind and load data (2003, 2004, and 2005) are sorted in descending order by load. Wind generation for the highest load hours is then summed, and the capacity factor for that number of hours is computed as an estimate of the contribution to system reliability.

An initial assessment of the capacity value of wind generation can be made with chronological wind and load data only. High load hours generally represent times when the system could be at risk of not having sufficient generation to meet demand. While these peak load hours may not represent the only times when the system is “at risk”, they are the major considerations for capacity planning studies.

Focusing only on the peak hours ignores the characteristics of the conventional generation portfolio, and assumes that load level is the only indicator of system reliability risk. It is, however, much less intensive in terms of data and computing time, and has been shown to provide an indication of the relative capacity contribution of wind generation in a particular system context.

The mathematical procedure is straightforward:

1. Construct a 2 x 8760 matrix, where the first column is hourly load and the second is hourly wind generation.
2. Sort the matrix of hourly load and wind generation pairs by the hourly load value, in descending order.
3. Calculate the wind energy delivery for the x highest load hours
4. Divide the wind energy delivered over those hours by the maximum that could have been delivered (installed capacity times number of hours)
5. Plot the results for various values of x.

Results of this procedure for each wind generation and load pattern year are shown in Figure 32.

GE-MARS Analysis

The data set developed for the most recent MAPP Reserve Capacity Obligation (RCO) review was updated to reflect the assumptions for this study. The new generation capacity per Figure 31 was added, using forced outage data from similar units already in the data set. Hourly loads in the Minnesota area were replaced by those developed for this study. Loads in other areas were scaled by the same factor used to develop the 2020 loads for Minnesota.

Wind is treated as a load modifier. This involves running two separate cases – one with load alone (no wind), and the other with the hourly loads net of wind generation. All three sets of wind and load patterns corresponding to calendar years 2003, 2004, and 2005 were used.

A significant amount of new capacity in the Minnesota area was required to bring the reliability level to the target 1 day in 10 years for the no wind case. This shows that the baseline generation expansion assumptions for the study would not provide adequate reliability for projected 2020 loads.

Results

Results of the GE-MARS simulations are presented in Figure 33 through Figure 35 and Table 21 through Table 23.

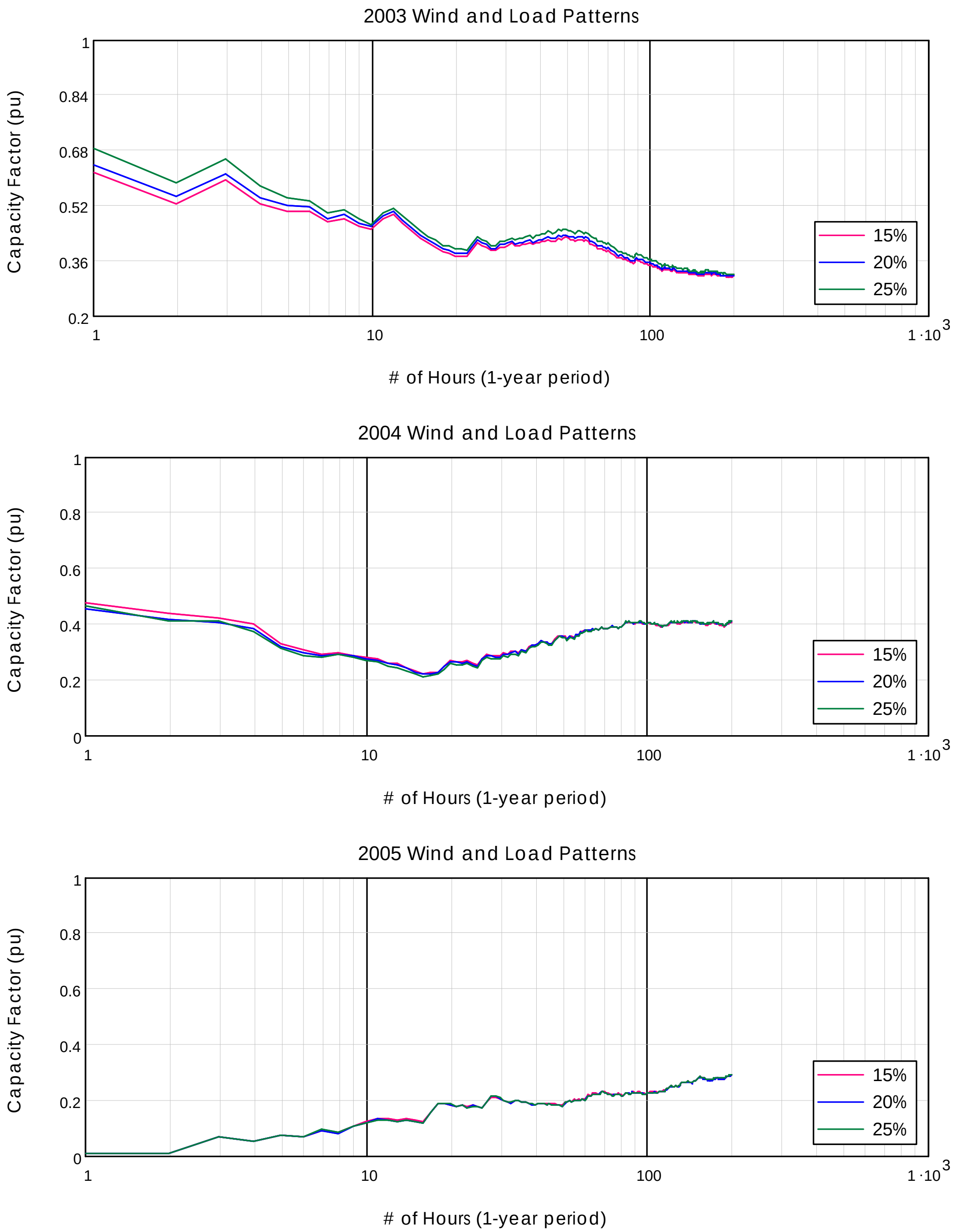


Figure 32: Wind generation capacity factor for varying number of highest load hours. (2003, 2004, and 2005 wind and load patterns)

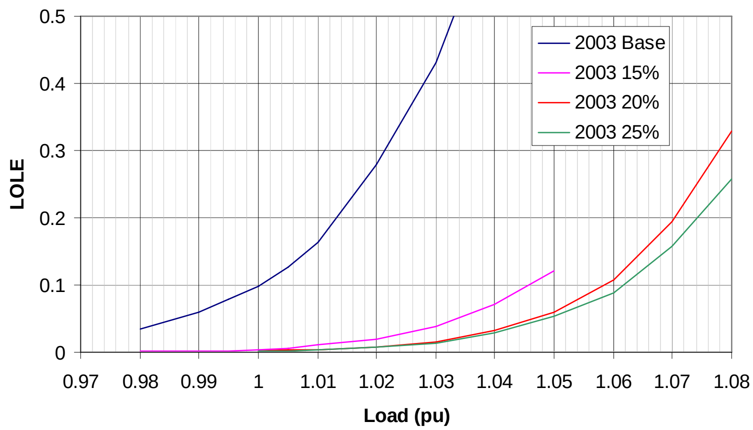


Figure 33: LOLE for Minnesota Area based on 2003 load and wind patterns

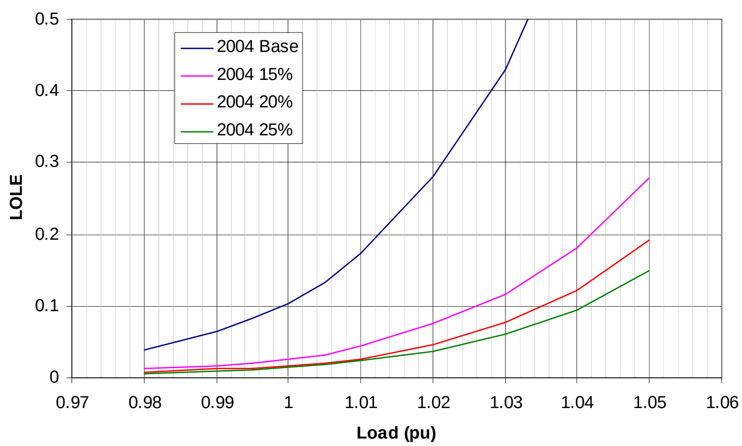


Figure 34: LOLE for Minnesota Area based on 2004 load and wind patterns

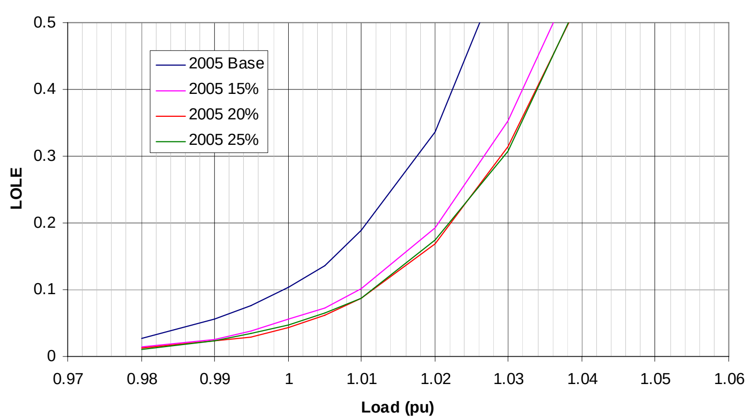


Figure 35: LOLE for Minnesota Area based on 2005 load and wind patterns

Table 21: ELCC Results for 2003 Wind and Load Patterns

Wind Penetration	ELCC (pu)	Peak Load (MW)	ELCC (MW)	Wind (MW)	ELCC (%)
15%	0.046	15630	719	3441	20.9%
20%	0.059	15630	922	4582	20.1%
25%	0.062	15630	969	5688	17.0%

Table 22: ELCC Results for 2004 Wind and Load Patterns

Wind Penetration	ELCC (pu)	Peak Load (MW)	ELCC (MW)	Wind (MW)	ELCC (%)
15%	0.026	15630	406	3441	11.8%
20%	0.035	15630	547	4582	11.9%
25%	0.041	15630	641	5688	11.3%

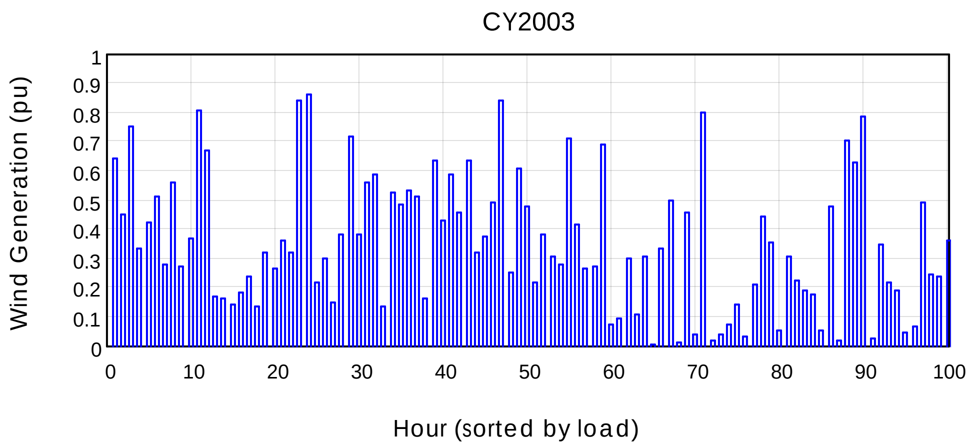
Table 23: ELCC Results for 2005 Wind and Load Patterns

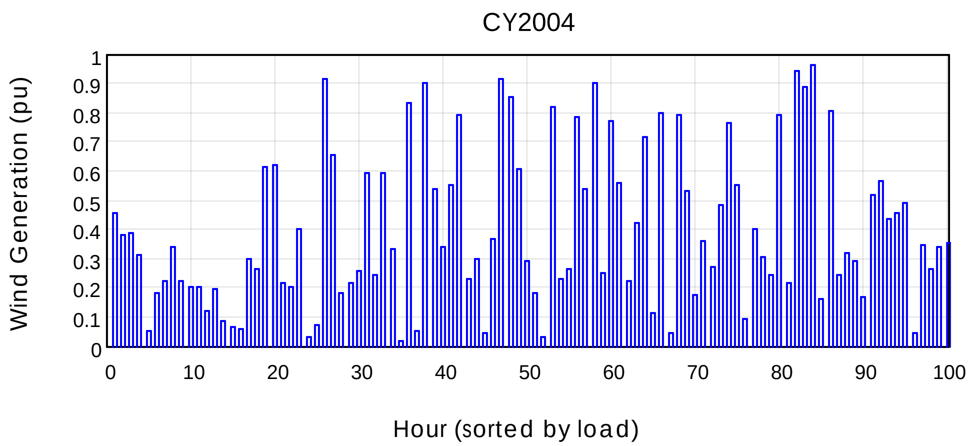
Wind Penetration	ELCC (pu)	Peak Load (MW)	ELCC (MW)	Wind (MW)	ELCC (%)
15%	0.01	15630	156	3441	4.5%
20%	0.015	15630	234	4582	5.1%
25%	0.015	15630	234	5688	4.1%

Discussion

Variation in ELCC between years is maybe the most surprising aspect of the results. Both load and wind patterns vary by year, and correspond to the meteorological conditions for those years. Results for calendar year 2003 wind and load patterns is in the range of what might have been expected from those who have been engaged in the wind capacity value discussion. In the other years, it is significantly lower.

The trend in the ELCC by year is consistent with what was found from the analysis of wind and load data only, in that 2003 shows the best correlation between wind production during the highest load hours, with 2005 exhibiting the poorest correlation. This is evident from the capacity factor over the highest load hours as shown in Figure 32. Examining hourly wind energy delivery for the highest load hours of each calendar year (Figure 36), rather than cumulative production as in Figure 32 provides an even better view. It is apparent from the plots that wind production was much lower during the highest load hours in 2005, especially in the highest 40 hours. In 2003, on the other hand, there was significant generation during those same hours, with 2004 somewhere between.





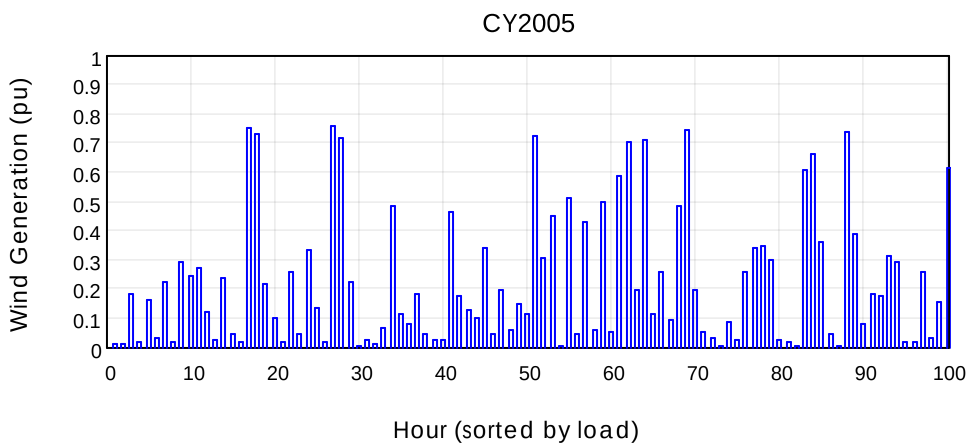


Figure 36: Hourly wind production for highest 100 load hours of year (20% scenario)

RESULTS FROM MARELLI

Marelli runs performed by MISO also show that the new capacity in the West RSG assumptions is not sufficient for the 2020 loads developed for this study. The same observation was made during the MARS analysis, but in those cases additional capacity was added to the Minnesota area to bring the reliability without wind generation to the target level. No such modification was made to the data for the initial Marelli analysis.

Results from the initial Marelli cases are shown graphically in Figure 37 through Figure 39.

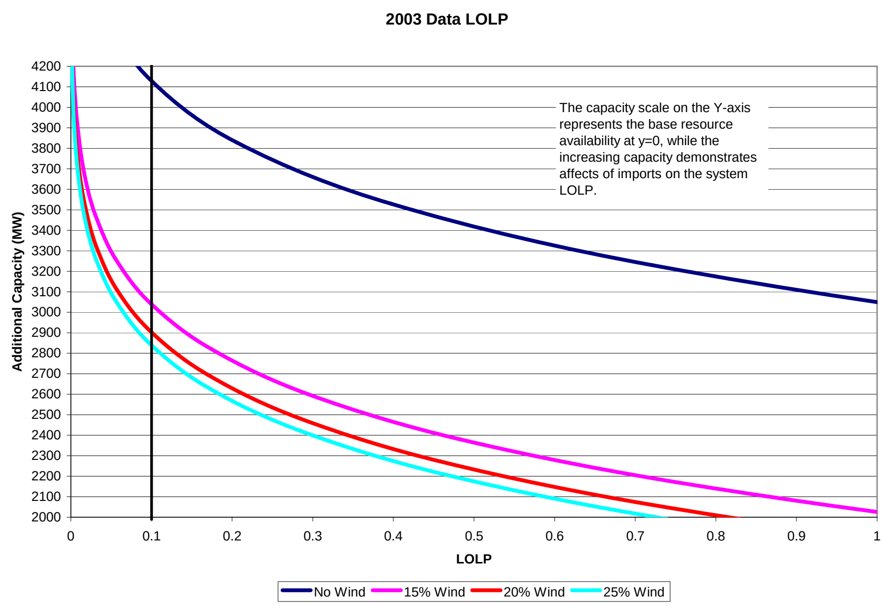


Figure 37: LOLH (Loss of Load Hours) from Marelli analysis for 2003 wind and load patterns

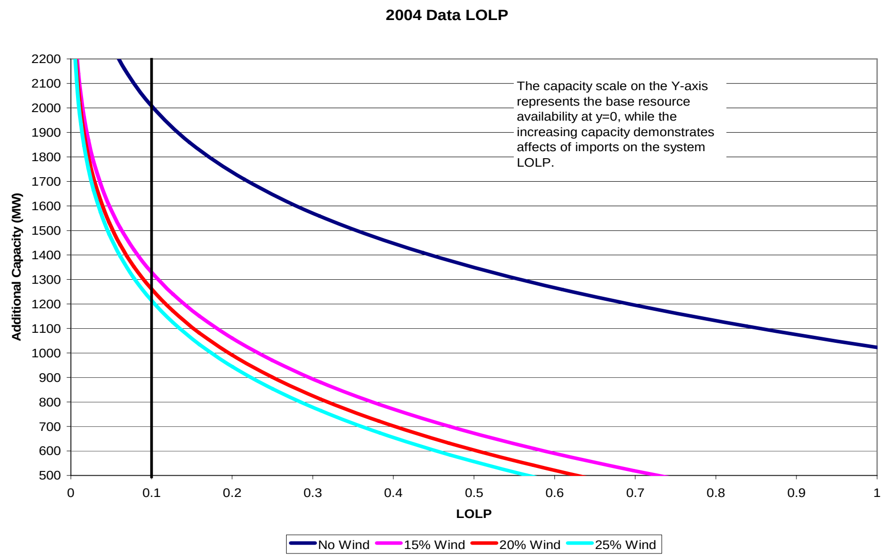


Figure 38: LOLH (Loss of Load Hours) from Marelli analysis for 2004 wind and load patterns

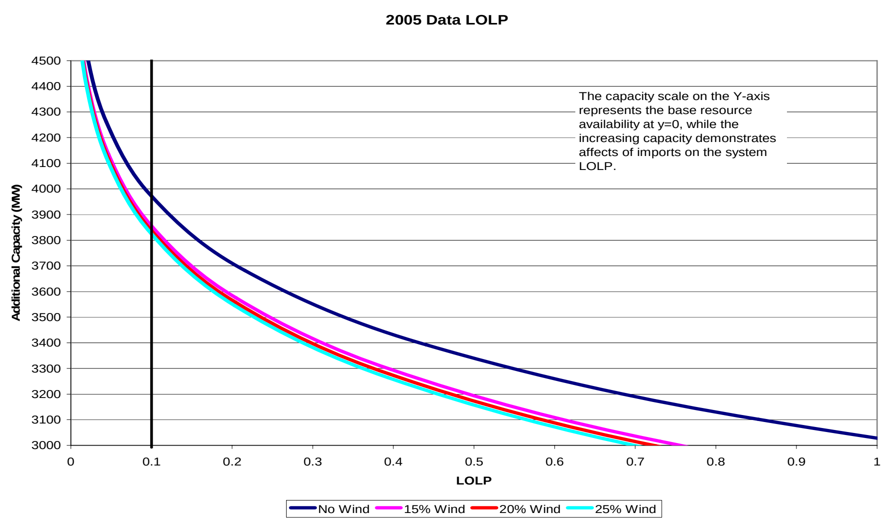


Figure 39: LOLH (Loss of Load Hours) from Marelli analysis for 2005 wind and load patterns

To allow for a more direct comparison, MARS cases were re-run to more closely match the assumptions used in the analysis by MISO. These are shown in Figure 40 through Figure 42.

A comparison of the ELCC results obtained from the GE-MARS and Marelli LOLP analysis is provided in Table 24.

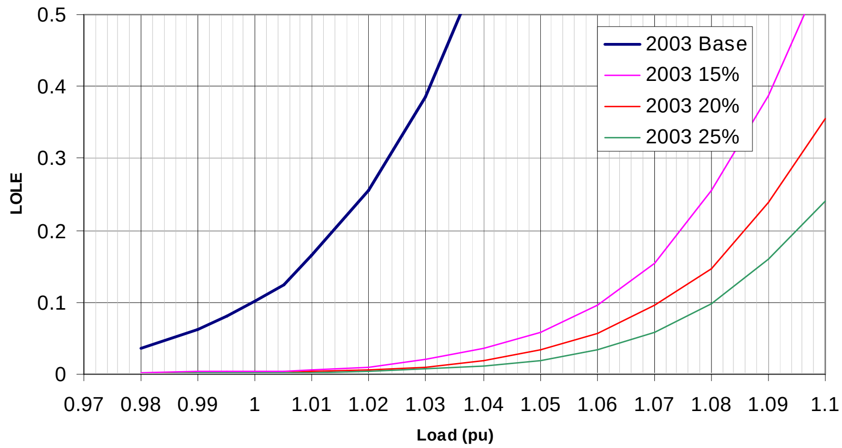


Figure 40: GE-MARS results for isolated MN system; 2003 wind and load patterns

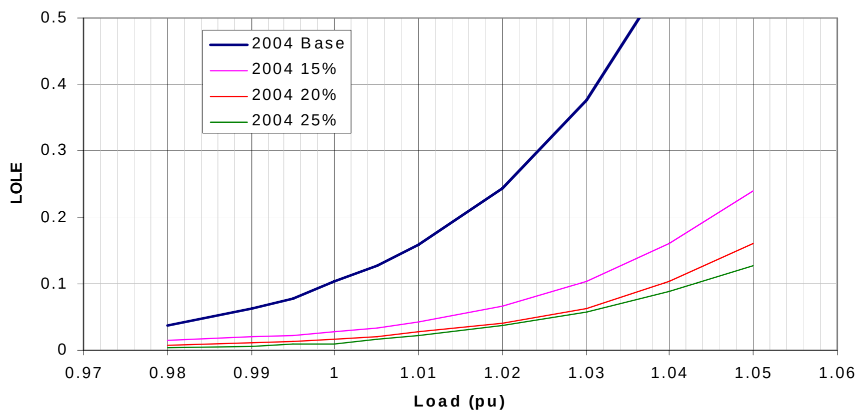


Figure 41 GE-MARS results for isolated MN system; 2004 wind and load patterns

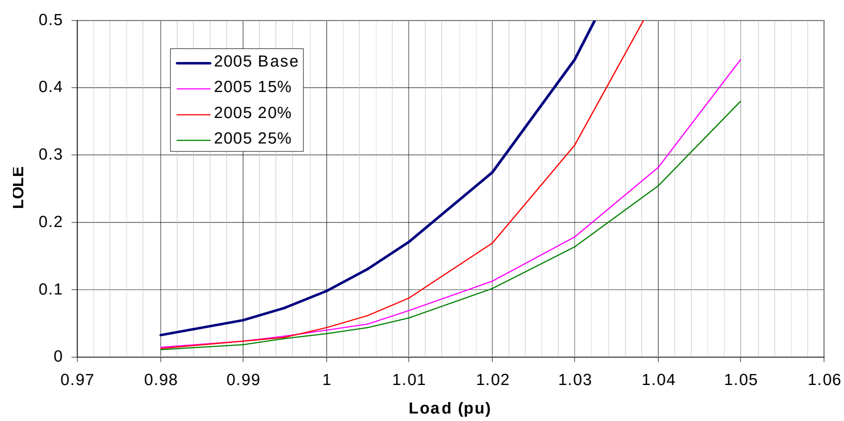


Figure 42: GE-MARS results for isolated MN system; 2005 wind and load patterns

Table 24: Comparison of ELCC Results from GE-MARS and Marelli LOLP Analysis

2003 Load Shape ELCC Analysis for Minnesota Load

GE-MARS Results

	pu dELCC	Peak Load	dELCC MW	Wind	% ELCC
15%	0.061	15630	953	3441	27.7%
20%	0.071	15630	1110	4582	24.2%
25%	0.081	15630	1266	5688	22.3%

Marelli Results

2003 Load Shape ELCC Analysis for Minnesota Load

	Cap Add (mw)	Base Cap Add (mw)	dELCC MW	Wind	% ELCC
15%	3050	4100	1050	3441	30.5%
20%	2900	4100	1200	4582	26.2%
25%	2825	4100	1275	5688	22.4%

2004 Load Shape ELCC Analysis for Minnesota Load

GE-MARS Results

	pu dELCC	Peak Load	dELCC MW	Wind	% ELCC
15%	0.029	15630	453	3441	13.2%
20%	0.039	15630	610	4582	13.3%
25%	0.043	15630	672	5688	11.8%

Marelli Results

2004 Load Shape ELCC Analysis for Minnesota Load

	Cap Add (mw)	Base Cap Add (mw)	dELCC MW	Wind	% ELCC
15%	1350	2000	650	3441	18.9%
20%	1260	2000	740	4582	16.2%
25%	1200	2000	800	5688	14.1%

2005 Load Shape ELCC Analysis for Minnesota Load

GE-MARS Results

	pu dELCC	Peak Load	dELCC MW	Wind	% ELCC
15%	0.012	15630	188	3441	5.5%
20%	0.017	15630	266	4582	5.8%
25%	0.02	15630	313	5688	5.5%

Marelli Results

2005 Load Shape ELCC Analysis for Minnesota Load

	Cap Add (mw)	Base Cap Add (mw)	dELCC MW	Wind	% ELCC
15%	3850	3980	130	3441	3.8%
20%	3835	3980	145	4582	3.2%
25%	3820	3980	160	5688	2.8%

Discussion

When run using the same wind generation and load patterns, and the same assumptions for modeling of the Minnesota power system, the ELCC results obtained through LOLP analysis with both GE-MARS and Marelli are consistent. Further support is obtained by analyzing more detailed output from the programs which indicates the weeks of the year from the respective simulations where generation was insufficient to meet load in the statistical trials. This output is shown in Figure 43 through Figure 45 for each pattern year, and requires some explanation.

The vertical axes on the charts represent different quantities; the time scale, however is synchronized. For each year it can be seen that the system was at some risk during the same periods. Even though the programs utilize different algorithmic approaches for the LOLP analysis, they both show that the combination of wind generation, load, maintenance outages, etc. during certain periods can result in loss of load if forced generation outages should occur

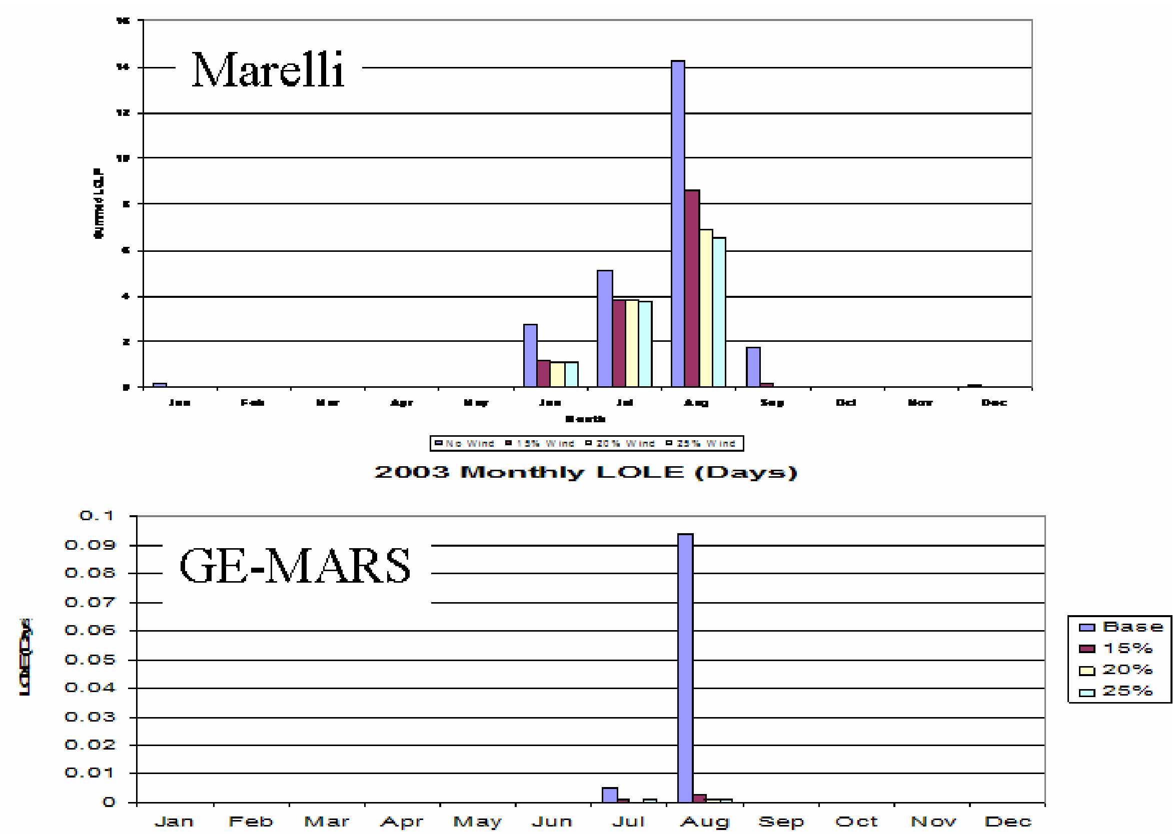


Figure 43: Weekly LOLP results for 2003 for GE-MARS and Marelli

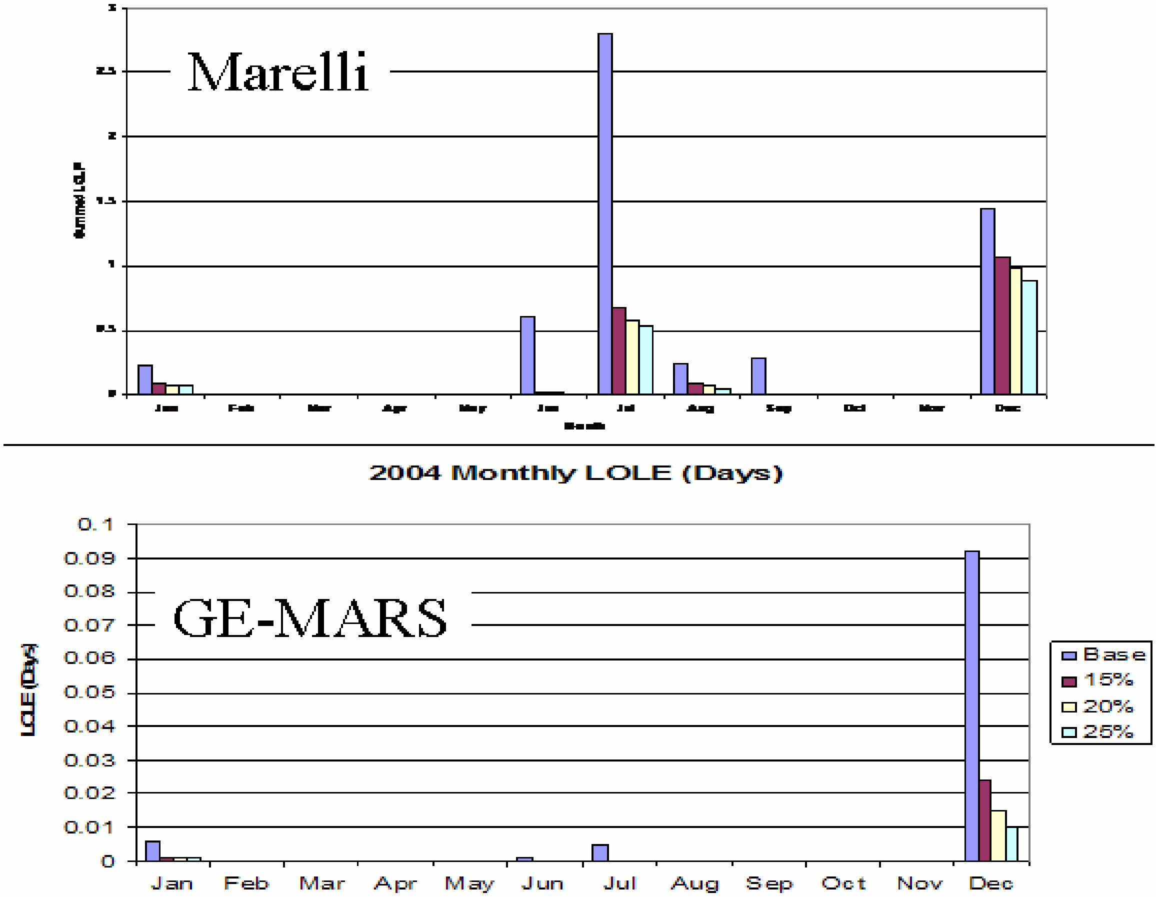


Figure 44: Weekly LOLP results for 2004 for GE-MARS and Marelli

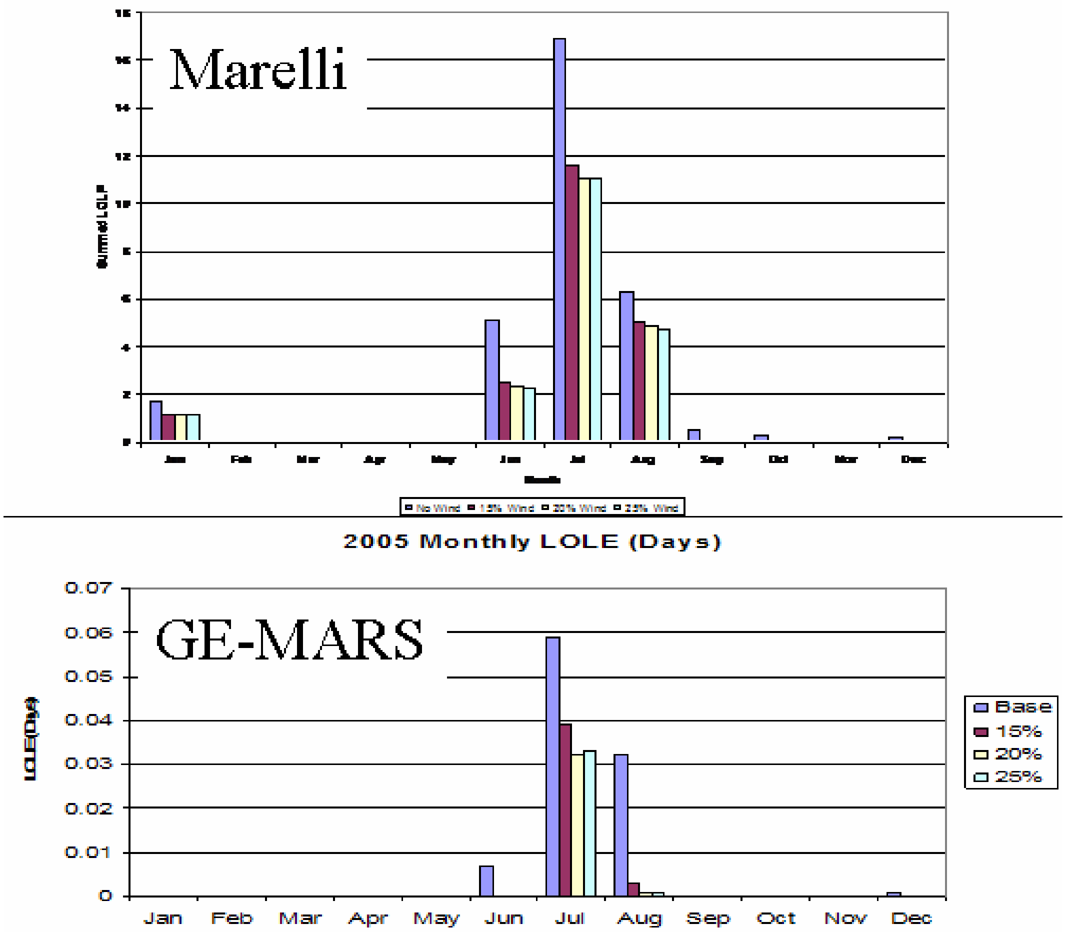


Figure 45: Weekly LOLP results for 2005 for GE-MARS and Marelli

The numerical results from the LOLP analysis are slightly lower than the capacity accreditation as determined by the existing MAPP Reserve Sharing Group policy for accrediting intermittent generation. This policy was first developed for small hydro systems, and uses an after-the-fact accounting procedure based on the amount of energy deliveries during a four hour window around the monthly peak hour. It is specified to be applied over a ten-year rolling window, so the monthly accredited capacity is actually the median value of the monthly samples over the previous decade.

Table 25 shows the results of applying the MAPP Generation Reserve Sharing Pool (GRSP) accreditation procedure to the wind model developed for this study. Of note are the accredited capacity values during the summer peak season, the months of July and August. These are median values from the peak period window over the three years. Unlike the LOLP analysis, all deliveries in the four hour window around the monthly peak hour are counted, even if the peak load for the month is significantly lower than would be expected. This was the case for 2004, where the peak actually occurred in the winter. Additionally, the MAPP methodology makes no distinction between days during the month. Over a period of a few days leading up to the monthly peak hour, wind generation may be low. As is often the case in the Great Plains, hot spells are broken by frontal passages that can bring vigorous winds. High wind generation during these periods also affects the statistic.

Table 25: Capacity Accreditation of Wind Generation for Study per MAPP RSG Methodology

	15% Penetration		20% Penetration		25% Penetration	
	MW	% of Wind	MW	% of Wind	MW	% of Wind
Jan	793	23%	1094	24%	1353	24%
Feb	783	23%	1034	23%	1231	22%
Mar	1261	37%	1661	36%	2056	36%
Apr	1503	44%	2032	45%	2557	45%
May	1674	49%	2215	48%	2743	48%
Jun	902	26%	1185	26%	1416	25%
Jul	715	21%	951	21%	1167	21%
Aug	674	20%	904	20%	1087	19%
Sep	1251	36%	1687	37%	2111	37%
Oct	1052	31%	1401	31%	1731	30%
Nov	1346	39%	1793	39%	2319	41%
Dec	1442	42%	1928	42%	2450	43%

SUMMARY

A variety of methods were employed to assess the contribution of the wind generation model developed for this study to the reliability of the Minnesota power system. The results were consistent across all of the methods, and show that the effective capacity of wind generation can vary significantly year-to-year. The ELCC of the wind generation corresponding to 15% to 25% of Minnesota retail electric sales ranges from approximately 5% to just over 20% of nameplate capacity.

Meteorological conditions are the most likely explanation for this variation, as it can affect both electric demand and wind generation. The historical years used as the basis for this study did exhibit some marked differences attributable to weather, especially in 2004 where the annual peak actually occurred in the winter, rather than in the late summer months as is the norm.

Capacity value as computed through a rigorous LOLP analysis, along with the average number derived with such methods as that utilized by the MAPP GRSP can be expected to improve and converge as more years of data are added to the sample.

Section 5

OPERATING IMPACTS

OVERVIEW

In the operating time frame – hours to days – wind generation and load follow different cycles. Load exhibits a distinct diurnal pattern through all seasons. Wind generation in the Great Plains exhibits some diurnal characteristics, but is mainly driven by the passage of large scale weather systems that have cycles of several days to a week. It is nearly impossible, therefore, to select a small number of “typical” wind and load days for analysis.

The approach first used in the study for Xcel Energy in 2004 overcomes this difficulty by utilizing synchronized historical load and wind generation data sets extending over several years. Correlations due to the common meteorology are automatically embedded in these records, and a much wider range of combinations of wind generation and load behavior are represented. With multiple annual data sets, inter-annual variations in the meteorology can be captured.

With these data sets as the starting point, assessment of wind integration issues can be accomplished through a “simulation” of operational activities. For most utilities, this involves a forward-looking process where resources are committed for operation based on forecasts of load and wind. The selected resources are then dispatched against the “actual” load and wind generation to simulate real-time operations. Using planning tools that operate on time steps of one hour, an entire annual set of wind and load data can be processed.

MISO utilizes PROMOD for hour-by-hour analysis of energy market operations and transmission facility utilization. In this program, generating units are committed based on costs, operating characteristics, and transmission constraints, then dispatched to meet the specified load on an hourly basis. Like other hourly production costing programs, it can be used as a “proxy” for the short-term operation of power systems.

In this study, PROMOD is utilized to simulate the operation of the MISO energy markets. Annual data sets of wind generation and load developed from synthesized and historical data for calendar years 2003, 2004, and 2005 are the primary inputs to the program. System characteristics, such as transmission network data and generating unit costs and capabilities, are drawn from the database that MISO utilizes for transmission planning studies.

“BASE” CASES

The initial PROMOD cases utilized the Minnesota load patterns from 2004 scaled to 2020 levels, and wind generation from the same year. Wind generation was injected at 14 buses in Minnesota and the Dakotas, and treated as a “firm” transaction. PROMOD uses firm transactions in the unit commitment step of the simulation, so the results represent an optimized commitment and dispatch for the entire year.

Output from the PROMOD analysis can include the hourly profile of load at any bus, flows in any line, or output from any generator. The results presented here and throughout this section are based on summary information, and consist of the following quantities:

- Load – The annual energy consumed by end-users in the Minnesota company footprints in the PROMOD case. The target Minnesota retail electric energy sales are based on load patterns from 2004. Units are terawatt-hours (TWH), which is 1 million MWH.
- Wind Generation – Annual energy delivered by the wind generation in the scenarios constructed for this study. The amount varies by year, with target fraction of retail electric energy sales for wind based on meteorology from the year 2004. Units are terawatt-hours (TWH), which is 1 million MWH.
- Generation (non-wind) – Annual electric energy production from conventional generating resources. Units are terawatt-hours (TWH), which is 1 million MWH.
- Load Cost – The annual amount paid by the loads for the electric energy consumed. This quantity is equal to the summation over all hours of the year and all utilization buses in the Minnesota companies' PROMOD footprints of the hourly amount at each utilization bus times the hourly locational marginal price at that utilization bus. Units are in millions of dollars.
- Production Cost – Variable costs associated with electric energy production. Includes fuel, startup and shutdown, and O&M costs. This amount does not include any consideration for capital recovery. Units are in millions of dollars.
- Generator Revenue – The annual amount paid to the generators. This quantity is equal to the summation over all hours of the year and all delivery buses in the Minnesota companies' PROMOD footprints of the hourly amount at each delivery bus times the hourly locational marginal price at that delivery bus. Units are in millions of dollars.
- Imports – The amount of energy utilized by loads in the Minnesota companies' PROMOD footprint but produced outside of that footprint. Units are terawatt-hours (TWH), which is 1 million MWH.

The case was run multiple times for different operating reserve assumptions to generate a curve for each wind generation level. Production costs and load payments are shown in Figure 46 and Figure 47. The effect on the utilization of conventional generation is shown in Figure 48 and Figure 49.

These optimized hourly cases show the following impacts of wind generation:

- As more wind energy is added, the production cost and load payments decline. This is due to the displacement of conventional generation and the resulting reduction in variable (fuel) costs.
- Generation from both coal and gas units is displaced.
- Production costs rise with the level of required operating reserves. This is intuitive, since more generation must be available or online.
- Production costs rise slowly from the baseline assumption of 5% total operating reserves out to about 7%. From there, costs rise more quickly.

- As the operating reserve requirement is increased, coal units are further displaced in favor of more flexible gas units.

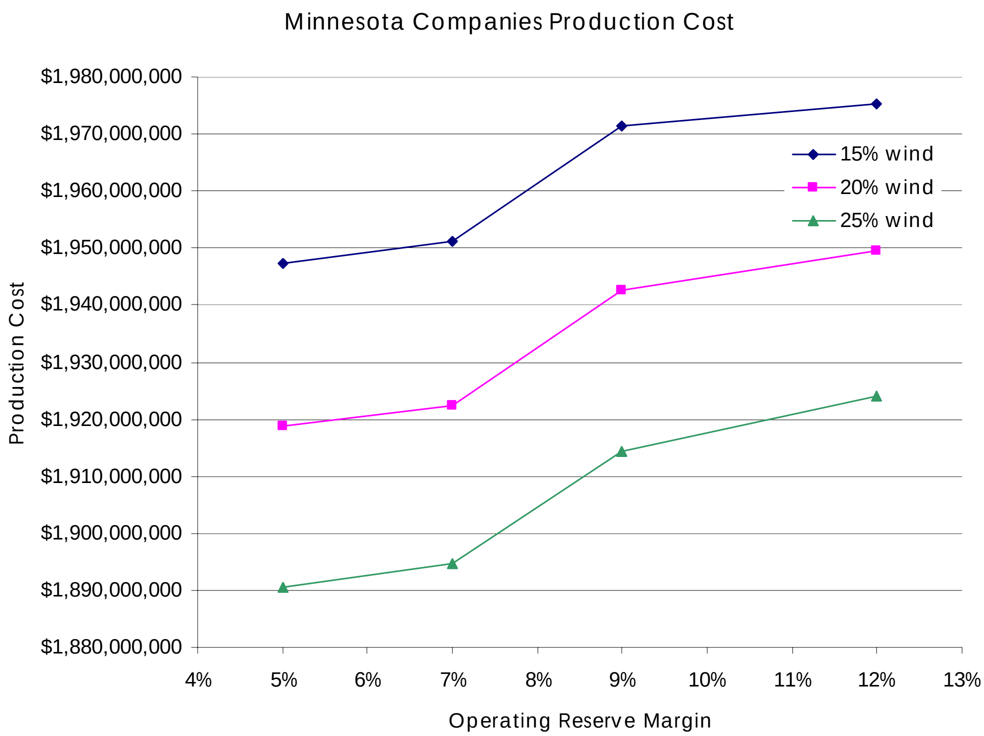


Figure 46: Production cost for Minnesota companies as a function of wind penetration and operating reserve level.

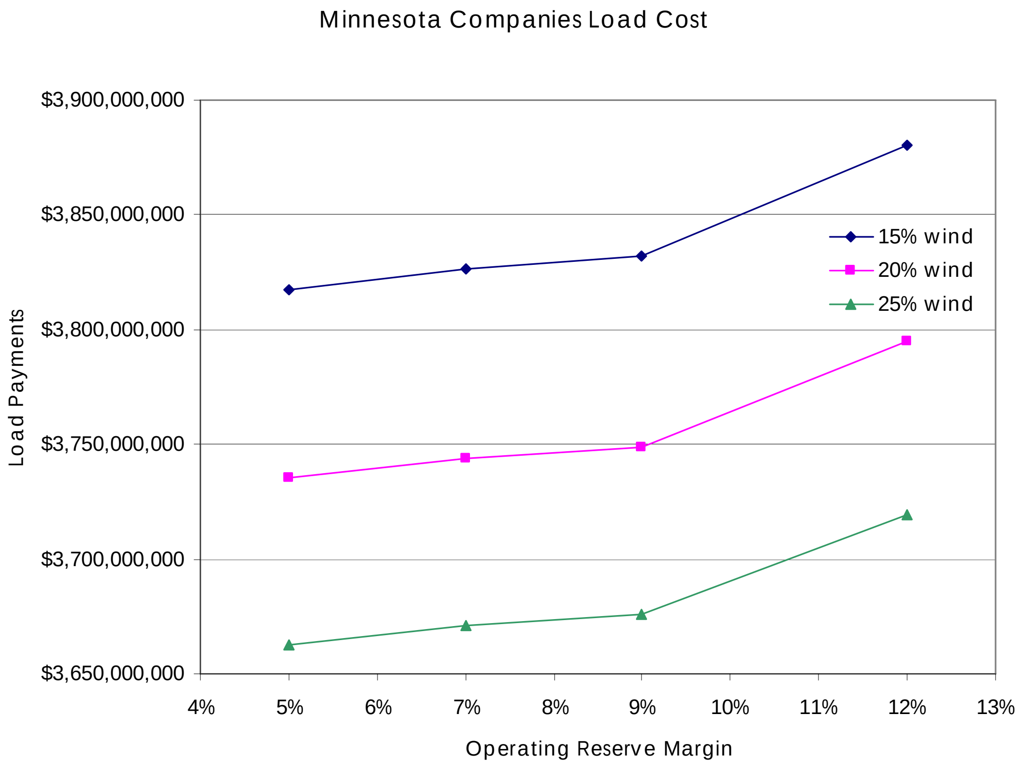
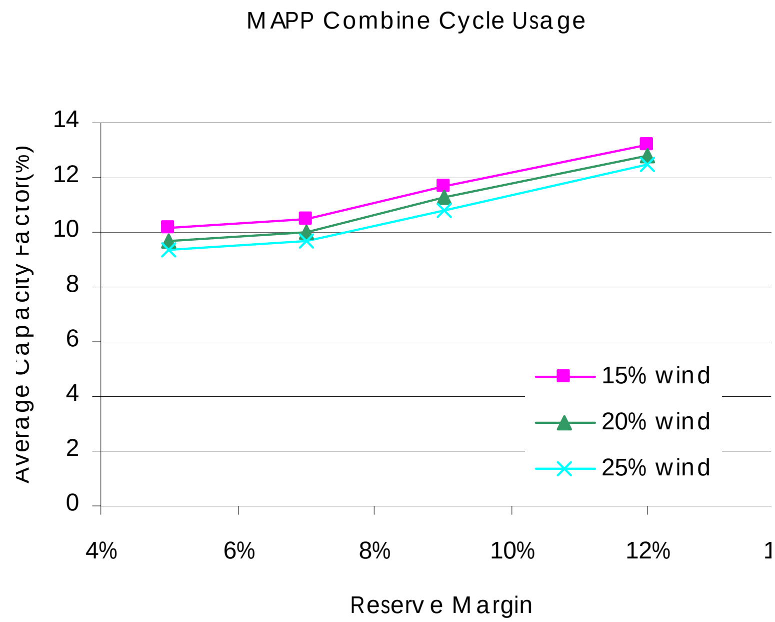


Figure 47: Load payments for Minnesota companies as a function of wind penetration and operating reserve level.



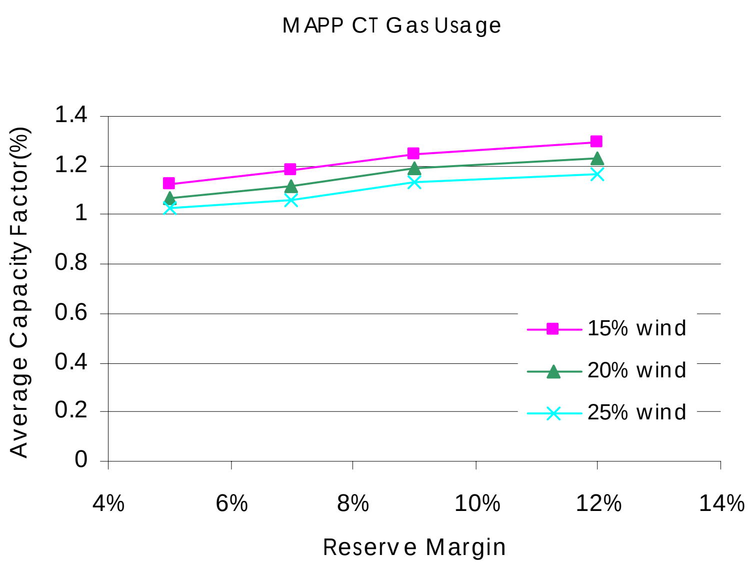
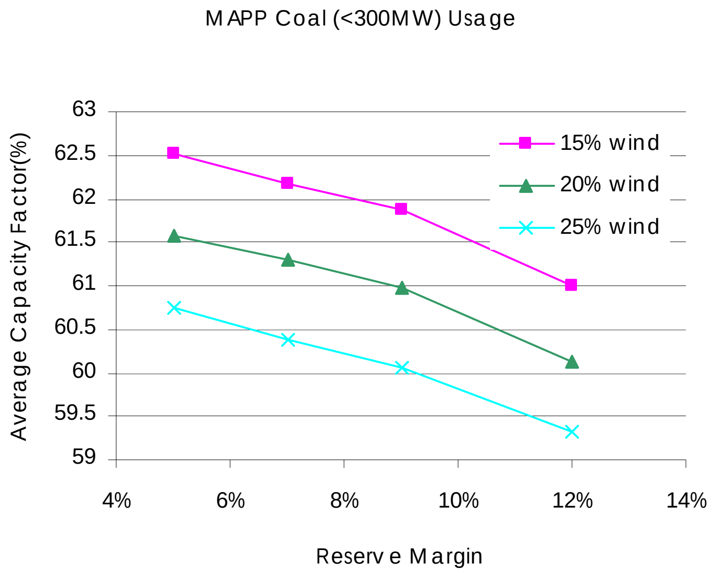


Figure 48: Gas unit capacity factor as functions of wind generation and operating reserve level



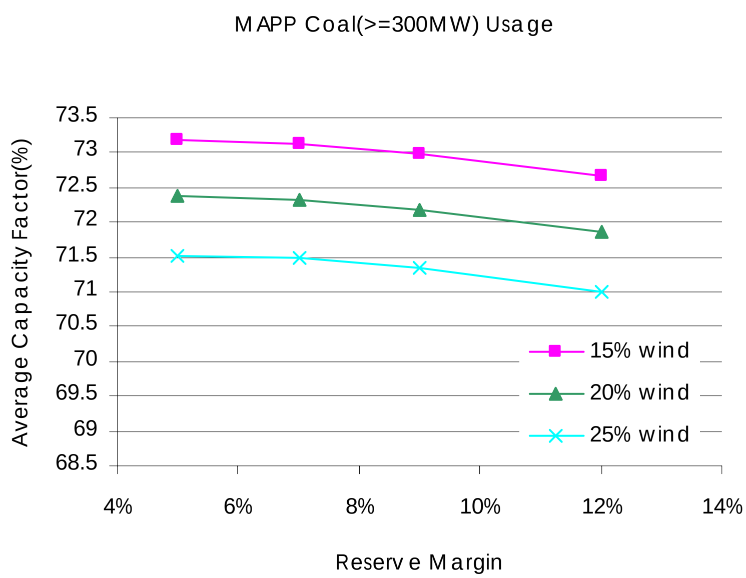


Figure 49: Coal unit capacity factor as functions of wind generation and operating reserve level

RESERVE COSTS

The base cases investigated costs as a function of operating reserve level. In the market impact cases, a single operating reserve percentage for each level of wind generation was assumed, based on the analysis. The reserve level in the market impact cases was also perturbed by a small amount in additional cases. Finally, a case where the operating reserve level was varied according to the amount of wind generation actually being delivered each hour was run.

2004 load and wind generation patterns were used in this analysis.

Figure 50 summarizes all reserve cases run, showing production cost as a function of operating reserve level. A trend line based on an exponential fit has been added to each wind penetration level.

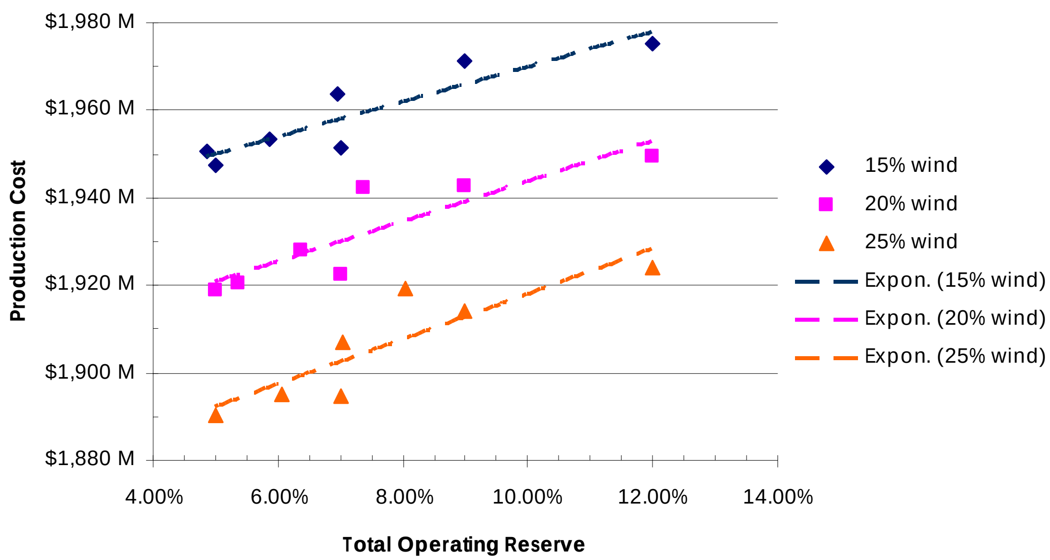


Figure 50: Production cost as a function of wind penetration and operating reserve level.

Production costs rise as total operating reserves are increased, which is the expected result. It is recognized, however, that a higher reserve requirement for all hours of the annual simulation is overly conservative, since there are many hours where wind generation is very low, and changes up or down would be of little note to operators. Further, an incremental operating reserve pegged to hourly changes in wind generation would not need to be comprised of spinning generation only – changes in the later part of the hour could be covered by quick-start units, if available. The significance here is that no costs accrue with this type of reserve unless it is used.

A case was run for the 2004 load patterns at 20% wind generation with operating reserves for wind generation modeled less conservatively:

- The additional operating reserve for wind generation is a variable hourly profile based on the previous hourly average value
- The incremental reserves for wind generation were further required only to be non-spinning.

As expected, these assumptions resulted in a decreased production costs over the fixed additional reserves case.

The cost associated with increased operating reserve can be placed in context by assigning it as an "integration cost" for wind generation and amortizing it over the wind energy delivered. Table 26 documents this calculation, and shows that for 20% wind generation, the fixed additional reserve options leads to a increased cost of $0.55 per

MWH of wind generation over the case where no additional reserves are carried. If the additional reserve amount is varied according to the quantity of wind generation actually being delivered over the hour, the cost per MWH of wind energy falls to $0.23.

If the operating reserve margin intended to cover unexpected declines in wind generation in the next hour (i.e. the negative deviation from a persistence forecast) is all allowed to consist of non-spinning quick-start units, the reserve cost per unit of wind energy declines further, to just $0.11/MWH. An interpretation is that there is enough quick-start reserve available over most hours of the year. Reserve costs would only be incurred if generation needed to be committed to cover this reserve requirement.

In all of these cases, the reserve component of the integration costs seems modest. This is likely a consequence of the very large number and diversity of the controllable resources in the MN footprint, With more units in operation, an increase in the reserve requirement can be accommodate without significantly changing the commitment of units to operation.

Table 26: Incremental Reserve Cost for 20% Wind Case, 2004 Patterns

Case	Production Cost
Full Reserves Case	$1,928 M
20% Variable Reserve Margin Case	$1,923 M
Operating Reserve Margin as non-spin	$1,921 M
Base Case - 5% Operating Reserve Assumption	$1,919 M
Wind Production - 20%/2004 Cases	*16,895,658 MWH*
Inremental Cost - "Full" Reserves	$9,368,744
Cost per MWH Wind	**$0.55**
Incremental Cost - "Variable" Reserves	$3,955,303
Cost per MWH Wind	**$0.23**
Incremental Cost - Variable Reserves, non-spin	$1,898,352
Cost per MWH Wind	**$0.11**

MARKET IMPACTS

The market impacts cases assumed a single operating reserve level for each penetration of wind generation, per Table 18 . The operating reserve levels were 5.86% for 15% wind generation, 6.36% for 20% wind, and 7.05% for 25% wind.

The PROMOD results constitute an “optimized” market scenario since wind generation and load are known perfectly in both the commitment and dispatch steps. Actual market operation would not be as efficient, and therefore at least somewhat more costly. This will be investigated in detail in the unit commitment cost quantification.

A further point should be made regarding the relationship of PROMOD to the actual operation of the MISO energy markets. PROMOD searches for an optimal economic solution given load, unit cost characteristics and constraints, and system requirements. In real energy market operation, bidding strategies and the mechanics of the market may result in a somewhat different deployment of units. If the market is liquid and transparent, however, the behavior should track the results from a cost-based analysis.

The following charts and graphs illustrate the effect of wind generation on various metrics of the MISO market and aggregate impact on other generators in Minnesota.

Table 27 shows how increasing wind generation displaces conventional generation in Minnesota, and the corresponding impacts on load payments and production cost.

The effect of wind generation on the locational margin price relative to a case with no wind generation at the Minnesota company trading hubs is shown in Figure 51 through Figure 53.

Finally, reductions in emissions relative to a case with no wind generation are provided in Table 28. In analyzing these emission reductions, it is important to remember that wind generation displaces both fossil generation and imports. In fact, for these cases, about two-thirds of the wind energy displaces imports from outside of the Minnesota company footprints. The emission reductions shown are for only those units within this footprint, so they do not reflect offsets from fossil units outside of Minnesota.

Table 27: Wind Generation Impacts on Energy Market Metrics – 2004 Wind and Load Patterns

Penetration Level	15%	20%	25%
Load	108.02 TWH	108.02 TWH	108.02 TWH
Wind Generation	12.67 TWH	16.90 TWH	21.18 TWH
Generation (non-wind)	90.83 TWH	89.77 TWH	88.66 TWH
Load Cost	$3,826 M	$3,745 M	$3,672 M
Production Cost	$1,953 M	$1,928 M	$1,907 M
Generator Revenue	$2,976 M	$2,891 M	$2,814 M
Imports	4.52 TWH	1.35 TWH	-1.82 TWH

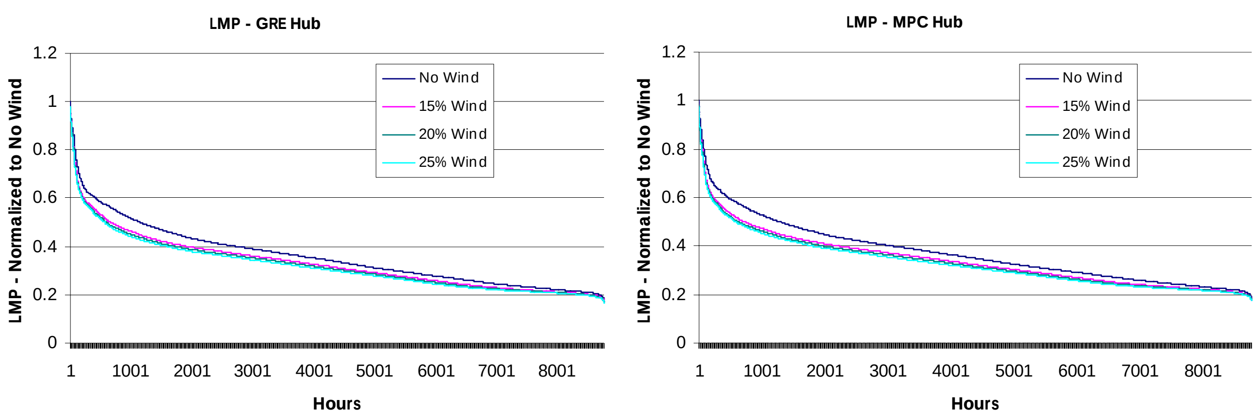


Figure 51: Wind generation impact on relative locational marginal price – Great River Energy and Minnkota hubs

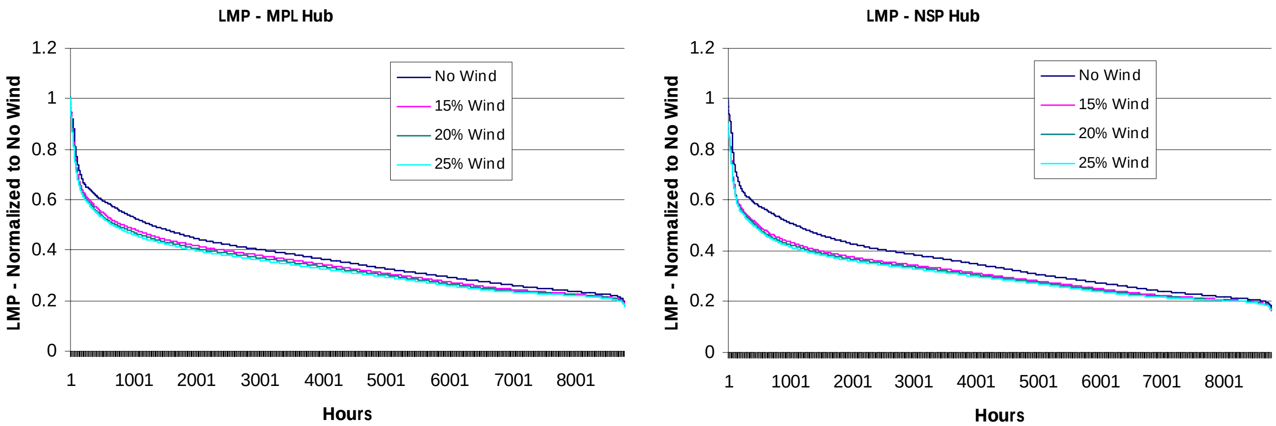


Figure 52: Wind generation impact on relative locational marginal price – Minnesota Power and Xcel Energy hubs

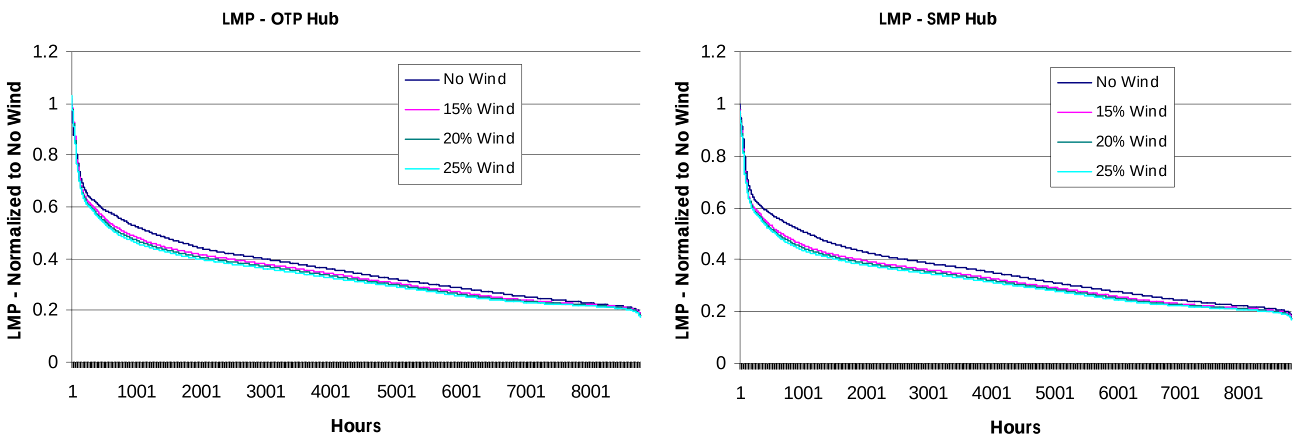


Figure 53: Wind generation impact on relative locational marginal price – Ottertail Power and Southern Minnesota Municipal Power Agency hubs

Table 28: MN Company Emissions for "No Wind" case and offsets for wind generation levels

	No Wind (*Metric Tons x1000)*	**Wind Generation Penetration**		
		15% (Base) *(Metric Tons x1000)*	*20%* *(Metric Tons x1000)*	*25%* *(Metric Tons x1000)*
CO2	53670	-1839	-2627	-3500
SOx	106.1	-3.3	-4.9	-6.7
NOx	148.6	-6.3	-9.2	-12.4

THE COST OF INTEGRATING WIND GENERATION

Background

The purpose of these hourly cases is to determine how the major characteristics of wind generation – variability and uncertainty – affect the commitment and dispatch of conventional generators.

The object of the analysis is to quantify the cost differential to serve the load not served by wind generation due to these characteristics. Using PROMOD and the data assembled for this study, this cost differential is determined through the following process:

1. Run PROMOD to simulate the MISO day-ahead market clearing and RAC (reliability assessment and commitment) process. In this step, the actual wind generation and load for the next day are not known perfectly. For wind generation, the day-ahead forecast developed in the resource characterization task is used. The load is more problematic. In the market clearing, demand bids, rather than actual forecasts, are used to clear the day-ahead offers. Later in the day, MISO performs a reliability assessment using security-constrained unit commitment, assesses this result versus the cleared offers. If the offers are short of what is determined necessary for reliability, more generation is committed. This process utilizes an actual forecast of load.

   If load is assumed to be known perfectly, all uncertainty costs will be attributed to wind generation, which is not the case in reality. PROMOD performs the unit commitment part of the simulation using only "firm" demand and transactions. From this commitment, an economic dispatch is performed against both firm and non-firm load and transactions. So to represent the actual wind generation in this sub-step, a second wind energy transaction was created. This non-firm transaction consists of the difference between forecast and actual wind generation.

   Load forecasts must also be handled through firm and non-firm transactions. In the commitment phase, firm transactions that represent the difference between actual and forecast loads are included. A non-firm transaction in the economic dispatch step is used to negate the firm transaction. What remains for dispatch, then, is the actual load.

2. A second reference case is analyzed with PROMOD where wind generation has no uncertainty or variability on a daily basis. The energy delivered over the course of each day, however, is identical to that in Step 1. Further, because of the attributes of this proxy energy resource, there are no additional reserves required to cover within the hour variability or short-term uncertainty.

3. The results of the unit commitment/economic dispatch simulation from the two cases are then compared. The differences in the load cost are assigned to the variability and uncertainty of wind generation.

The unit commitment component of the integration cost measures how the variability and uncertainty of wind generation decreases the efficiency of the market. The uncertainty impact shows up in the day-ahead market clearing, as significant wind generation forecast errors cause the market to respond to incorrect information. Over- and under-commitment of conventional generation will increase costs. The variability cost results from conventional units being dispatched "around" wind energy delivery. Increased costs result from less efficient operation of conventional units.

Results of PROMOD Cases

Case summary data and unit commitment cost calculations for the three wind generation penetration levels with 2003, 2004, and 2005 wind and load patterns are shown in Table 31. The numbers tabulated are for Minnesota loads and Minnesota companies. The total load shown is taken directly from the PROMOD output. This total includes retail load outside of Minnesota, and therefore is larger than the amount projected for the 2020 study year. As described in a previous section covering the development of the load model for the study, there is no practical way to segregate only the Minnesota load from the Minnesota company totals from the MISO West RSG PROMOD model.

These results show that, relative to the same amount of energy stripped of variability and uncertainty of the wind generation, there is a cost paid by the load that ranges from a low of $2.11 (for 15% wind generation, based on year 2005) to a high of $4.41 (for 25% wind generation, based on year 2003) per MWH of wind energy delivered to the Minnesota companies. This is a total cost and includes the cost of the additional reserves (per the assumptions) and costs related to the variability and day-ahead forecast error for wind generation. Integration cost results are shown graphically in Figure 54.

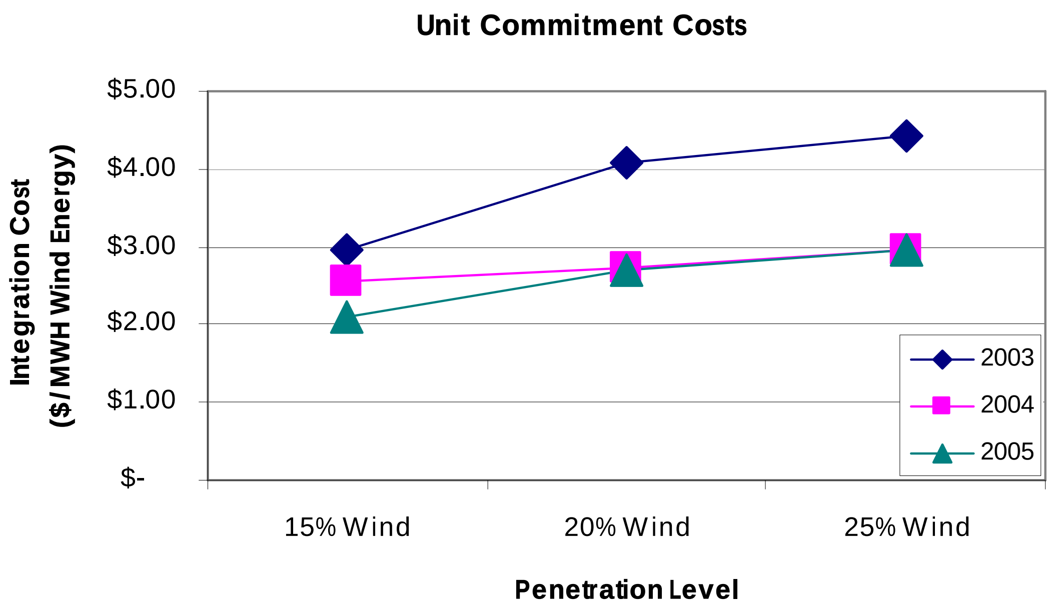


Figure 54: Unit commitment costs for three penetration levels and pattern years. Cost of incremental operating reserves is embedded.

IMPACTS OF WIND GENERATION ON UNIT UTILIZATION AND TRANSACTIONS

Results from the PROMOD cases described thus far show that energy from wind generation displaces conventional generation in the Minnesota company footprint. Some of the displaced generation is from more expensive gas units, but with the resource profile and the relatively high penetration of wind generation in the lower load seasons, it is possible that baseload units could be impacted.

An extra PROMOD case was run with the hourly dispatch profiles for all units in the Minnesota footprint larger than 200 MW reported. This case used 2004 load and wind patterns, and allowed PROMOD to optimize the solution (i.e. no wind generation or load forecast errors were considered). The analysis does appear to indicate some displacement of large coal generation by wind since production does go to zero for certain of the units throughout the year, not just during maintenance outage periods. Annual capacity factors however, remain 70% or greater for all of these units (not shown).

Wind generation also displaces imports into the Minnesota company footprint. Table 29 shows the load, wind generation, production from conventional generation, and imports for the 20% case with 2004 wind and load patterns. The table rows correspond to a case with no wind generation, and cases with different treatments of wind generation in the day-ahead unit commitment. If all wind generation is discounted in the day ahead commitment and allowed to show up in real time, about two-thirds of the wind generation would displace imports from outside of Minnesota. That amount is slightly increased if wind is incorporated, either through perfect knowledge or forecast, into the day-ahead commitment. This treatment increases production from Minnesota generators and further reduces imports.

Table 29: Load and Production for 20% Case, 2004 Patterns

Case	Load (TWH)	Wind Generation (TWH)	Generation (TWH)	Import (TWH)
No wind	108.02	0.00	93.49	14.53
No Commit Credit	108.02	16.90	87.92	3.21
Forecast	108.02	16.88	89.72	1.42
Perfect Forecast	108.02	16.90	89.77	1.35

EFFECT OF WIND GENERATION FORECASTING

How wind generation is treated in the commitment process has influence on market operations. Table 30 provides financial numbers for the cases described in the previous section. In terms of straight production cost for the Minnesota companies, excluding wind generation from the day ahead commitment reduces production cost since the Minnesota generators are "backed down" by over 5 TWH from the "no wind" case, along with a reduction in imports. However, if the cost of imports is included in a modified "production cost" equation, the effect of forecasting can be seen.

The PROMOD case results did not include hourly imports and prices, so an estimate of the cost of the imports is necessary. The last column in Table 30 assumes an average price of $40/MWH for imports. The variable cost reduction – made up of production costs plus purchased energy – is about $19 million greater when wind generation forecasts are considered in the unit commitment over the case where wind generation shows up in real time. These reductions are summarized in Figure 55.

Of possibly more significance are the generation revenue and load payment reductions. Allowing wind to show up in real time introduces significant market inefficiencies that result in large reductions in both load payments and generator revenue. Although apparently a "good deal" for the loads, over the long term this would be detrimental for market function.

Wind generation forecasts are important to energy market efficiency. If the amount of wind generation considered in this study is excluded from the day-ahead market clearing and reliability assessment commitment, the market participants will effectively be responding to incorrect signals. Without considering the probable wind energy deliveries, generation will be offered into the market to serve load that does not appear.

Table 30: Summary of Case Results for various treatment of wind in unit commitment (2004 wind and load patterns)

Case	Production Cost ($M)	Generation Revenue ($M)	Load Cost ($M)	Import (TWH)	Production Cost w/ Imports ($M)
No wind	2041.16	3278.47	4136.42	14.53	2767.63
No Commit Credit	1875.33	2649.19	3488.41	3.21	2035.83
Forecast	1928.06	2901.47	3756.69	1.42	1999.02
Perfect Forecast	1928.17	2891.47	3744.82	1.35	1995.78

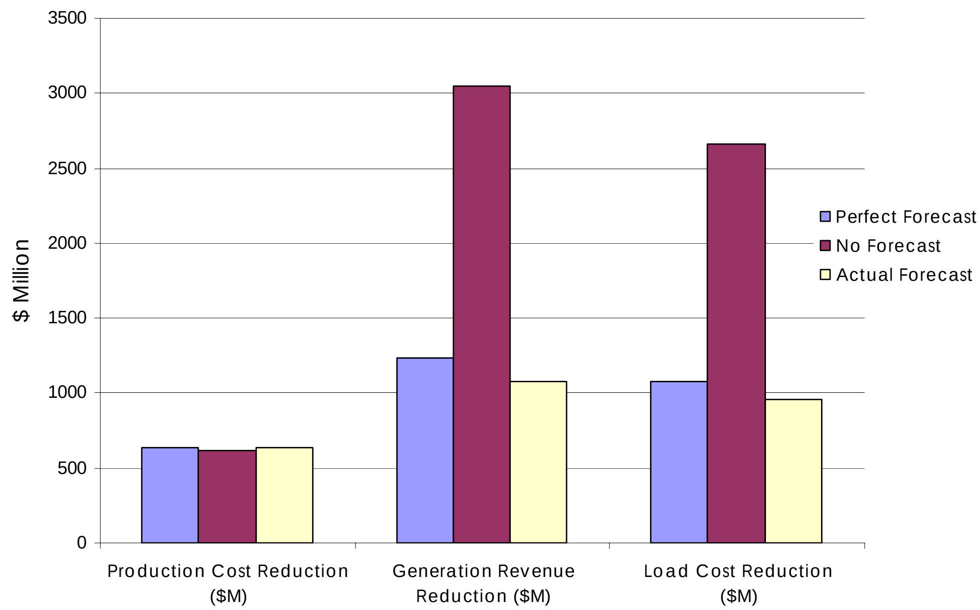


Figure 55: Effect of wind generation forecast on Minnesota company production and load costs

Table 31: Summary of Unit Commitment Cases: Variable Reserve, Load and Wind Forecast Error in Unit Commitment

15% Penetration/2003 Load Patterns

	Block	Mkt. Sim	Delta
Load	116.28 TWH	116.28 TWH	
Wind Generation	12.56 TWH	12.56 TWH	
Generation (non-wind)	92.87 TWH	94.94 TWH	2.06 TWH
Load Cost	$4,423 M	$4,460 M	$37 M
Production Cost	$2,017 M	$2,069 M	$52 M
Generator Revenue	$3,229 M	$3,260 M	$31 M
Wind Revenue	$419 M	$404 M	-$16 M
Imports + Losses	10.84 TWH	8.78 TWH	-2.06 TWH
Integration Cost - Unit Commitment (Load cost differential)			$37 M
Integration Cost			**$2.97 /MWH**

15% Penetration/2004 Load Patterns

	Block	Mkt. Sim	Delta
Load	108.02 TWH	108.02 TWH	
Wind Generation	12.66 TWH	12.66 TWH	
Generation (non-wind)	91.15 TWH	93.10 TWH	1.96 TWH
Load Cost	$3,814 M	$3,847 M	$32 M
Production Cost	$1,947 M	$1,989 M	$42 M
Generator Revenue	$2,972 M	$2,982 M	$10 M
Wind Revenue	$396 M	$384 M	-$13 M
Imports + Losses	4.22 TWH	2.26 TWH	-1.96 TWH
Integration Cost - Unit Commitment (Load cost differentia			$32 M
Integration Cost			**$2.55 /MWH**

15% Penetration/2005 Load Patterns

	Block	Mkt. Sim	Delta
Load	116.78 TWH	116.78 TWH	
Wind Generation	12.83 TWH	12.83 TWH	
Generation (non-wind)	92.94 TWH	94.98 TWH	2.03 TWH
Load Cost	$4,430 M	$4,457 M	$27 M
Production Cost	$2,016 M	$1,952 M	-$64 M
Generator Revenue	$3,224 M	$3,304 M	$79 M
Wind Revenue	$426 M	$408 M	-$19 M
Imports + Losses	11.01 TWH	8.98 TWH	-2.03 TWH
Integration Cost - Unit Commitment (Load cost differential			$27 M
Integration Cost			**$2.11 /MWH**

20% Penetration/2003 Load Patterns

	Block	Mkt. Sim	Delta
Load	116.28 TWH	116.28 TWH	
Wind Generation	16.75 TWH	16.75 TWH	
Generation (non-wind)	92.02 TWH	95.06 TWH	3.03 TWH
Load Cost	$4,313 M	$4,382 M	$68 M
Production Cost	$1,990 M	$2,059 M	$69 M
Generator Revenue	$3,136 M	$3,260 M	$124 M
Wind Revenue	$540 M	$518 M	-$21 M
Imports + Losses	7.51 TWH	4.47 TWH	-3.03 TWH
Integration Cost - Unit Commitment (Load cost differential)			$68 M
Integration Cost			**$4.09 /MWH**

20% Penetration/2004 Load Patterns

Case	Block	Mkt. Sim	Delta
Load	108.02 TWH	108.02 TWH	
Wind Generation	16.88 TWH	16.88 TWH	
Generation (non-wind)	90.19 TWH	93.15 TWH	2.96 TWH
Load Cost	$3,723 M	$3,770 M	$46 M
Production Cost	$1,921 M	$1,979 M	$58 M
Generator Revenue	$2,872 M	$2,990 M	$118 M
Wind Revenue	$513 M	$493 M	-$20 M
Imports + Losses	0.96 TWH	-2.01 TWH	-2.96 TWH
Integration Cost - Unit Commitment (Load cost differentia			$46 M
Integration Cost			**$2.73 /MWH**

20% Penetration/2005 Load Patterns

	Block	Mkt. Sim	Delta
Load	116.78 TWH	116.78 TWH	
Wind Generation	17.16 TWH	17.16 TWH	
Generation (non-wind)	92.04 TWH	95.09 TWH	3.05 TWH
Load Cost	$4,317 M	$4,364 M	$46 M
Production Cost	$1,988 M	$2,009 M	$22 M
Generator Revenue	$3,123 M	$3,237 M	$114 M
Wind Revenue	$550 M	$524 M	-$26 M
Imports + Losses	7.58 TWH	4.53 TWH	-3.05 TWH
Integration Cost - Unit Commitment (Load cost differential			$46 M
Integration Cost			**$2.71 /MWH**

25% Penetration/2003 Load Patterns

	Block	Mkt. Sim	Delta
Load	116.28 TWH	116.28 TWH	
Wind Generation	20.96 TWH	20.95 TWH	
Generation (non-wind)	91.20 TWH	94.78 TWH	3.59 TWH
Load Cost	$4,216 M	$4,308 M	$92 M
Production Cost	$1,966 M	$1,989 M	$23 M
Generator Revenue	$3,048 M	$3,237 M	$189 M
Wind Revenue	$648 M	$620 M	-$29 M
Imports + Losses	4.13 TWH	0.54 TWH	-3.59 TWH
Integration Cost - Unit Commitment (Load cost differential)			$92 M
Integration Cost			**$4.41 /MWH**

25% Penetration/2004 Load Patterns

	Block	Mkt. Sim	Delta
Load	108.02 TWH	108.02 TWH	
Wind Generation	21.10 TWH	21.10 TWH	
Generation (non-wind)	89.22 TWH	92.77 TWH	3.55 TWH
Load Cost	$3,644 M	$3,704 M	$60 M
Production Cost	$1,894 M	$1,967 M	$73 M
Generator Revenue	$2,801 M	$2,974 M	$173 M
Wind Revenue	$617 M	$590 M	-$27 M
Imports + Losses	-2.30 TWH	-5.85 TWH	-3.55 TWH
Integration Cost - Unit Commitment (Load cost differentia			$60 M
Integration Cost			**$2.83 /MWH**

25% Penetration/2005 Load Patterns

	Block	Mkt. Sim	Delta
Load	116.78 TWH	116.78 TWH	
Wind Generation	21.57 TWH	21.57 TWH	
Generation (non-wind)	91.09 TWH	94.68 TWH	3.59 TWH
Load Cost	$4,214 M	$4,278 M	$64 M
Production Cost	$1,960 M	$2,008 M	$48 M
Generator Revenue	$3,028 M	$3,205 M	$177 M
Wind Revenue	$661 M	$624 M	-$37 M
Imports + Losses	4.12 TWH	0.53 TWH	-3.59 TWH
Integration Cost - Unit Commitment (Load cost differential			$64 M
Integration Cost			**$2.95 /MWH**

Section 6

CONCLUSIONS

The analytical results from this study show that the addition of wind generation to supply 20% of Minnesota retail electric energy sales can be reliably accommodated by the electric power system if sufficient transmission investments are made to support it.

The degree of the operational impacts was somewhat less than expected by those who have participated in integration studies over the past several years for utilities around the country. The technical and economic impacts calculated are in the range of those derived from other analyses for smaller penetrations of wind generation.

Discussion of the analytical results with the Technical Review Committee (TRC) and the Minnesota utility company representatives has established the following as the key findings and the principal reasons that wind generation impacts were not larger:

1. These results show that, relative to the same amount of energy stripped of variability and uncertainty of the wind generation, there is a cost paid by the load that ranges from a low of $2.11 (for 15% wind generation, based on year 2003) to a high of $4.41 (for 25% wind generation, based on year 2005) per MWH of wind energy delivered to the Minnesota companies. This is a total cost and includes the cost of the additional reserves (per the assumptions) and costs related to the variability and day-ahead forecast error for wind generation.
2. The cost of additional reserves above the assumed levels attributable to wind generation is included in the total integration cost. Special hourly cases were run to isolate this cost, and found it to be about $0.11/MWH of wind energy at 20% penetration by energy.
3. The TRC decision to combine the Minnesota balancing authorities into a single functional balancing authority had a significant impact on results. Sharing balancing authority functions substantially reduces requirements for certain ancillary services such as regulation and load following (with or without wind generation). The required amount of regulation capacity is reduced by almost 50%. Additional benefits are found with other services such as load following. In addition, there are a larger number of discrete units available to provide these services.
4. The expanse of the wind generation scenario, covering Minnesota and the eastern parts of North and South Dakota, provides for substantial "smoothing" of wind generation variations. This smoothing is especially evident at time scales within the hour, where the impacts on regulation and load following were almost negligible. Smoothing also occurs over multiple hour time frames, which reduces the burden on unit commitment and dispatch, assuming that transmission issues do not intervene to affect operations. Finally, the number of hours at either very

high or very low production are reduced, allowing the aggregate wind generation to behave as a more stable supply of electric energy

5. The transmission expansion as described in the assumptions and detailed in Appendix A combined with the decision to inject wind generation at high voltage buses was adequate for transportation of wind energy in all of the scenarios. Under these assumptions, there were no significant congestion issues attributable to wind generation and no periods of negative Locational Marginal Price (LMP) observed in the hourly simulations.
6. The MISO energy market also played a large role in reducing wind generation integration costs. Since all generating resources over the market footprint are committed and dispatched in an optimal fashion, the size of the effective system into which the wind generation for the study is integrated grows to almost 1200 individual generating units. The aggregate flexibility of the units on line during any hour is adequate for compensating most of the changes in wind generation.

   The magnitude of this impact can be gauged by comparing results from recent integration studies for smaller systems. In the 2004 study for Xcel Energy, for example, integration costs were determined to be no higher than $4.60/MWH for a wind generation penetration by capacity of 15%, which would be closer to 10% penetration on an energy basis.
7. The contribution of wind generation to power system reliability is subject to substantial inter-annual variability. Annual Effective Load Carrying Capability (ELCC) values for the three wind generation scenarios from rigorous Loss of Load Probability (LOLP) analysis ranged from a low of 5% of installed capacity to just over 20%. These results were consistent with those derived through approximate methods.

Section 7

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APPENDIX A – WEST RSG STUDY ASSUMPTIONS

Note: The following is a reproduction of the assumptions document for the West Regional Studies Group (RSG) dated May, 2006. The base model for the West RSG is the starting point for the Minnesota PUC wind integration study.

INTRODUCTION

There are several exploratory studies performed in West Region. These studies are: CapX 2020, Buffalo Ridge Incremental Generation Outlet (BRIGO) study, Southwest Minnesota to Twin Cities EHV Development study, Southeastern Minnesota – Southwestern Wisconsin Reliability Enhancement Study, American Transmission Company (ATC) Access Project study, NW Exploratory study, Iowa-Southern Minnesota exploratory study. The transmission upgrades proposed in these studies are corresponding to their generation scenario assumptions.

The West RSG is a collaborative effort of MISO staff, the MISO Transmission Owners, stakeholders, regulatory staff and a voluntary participation of SEAMS transmission owners to direct the studies for the MISO Transmission Expansion Plan. Midwest ISO is trying to roll the results of all the above exploratory studies into one study – West RSG Exploratory Study. This collaborative study will be included in MTEP for information purpose. The Goal of this collaborative study is to determine if transmission needs to be built for energy delivery, REO or economics. It can also determine multi-use requirements that may not be supportable by a single entity.

The West RSG study is based on the MAPPMAIN reduced footprint, the topology is shown in the above figure, a total of 34 companies are included in the MAPPMAIN reduced footprint.

FUEL FORECAST[3]

The source for the fuel forecasts in the Powerbase database is the Platt's database, Henry hub forecasts and EIA forecasts. New Energy Associates (NEA) contracts with Platt's for various fuel forecasts. NEA starts with Platt's forecasts for natural gas and then uses the basis differential inherent in Platt's forecast for Natural Gas combined with NYMEX Henry Hub futures prices for the first 18 months of the forecast. For the forecast beyond 18 months, the Energy Information Administration (EIA) natural gas forecast for the Henry Hub serves as the base index. The basis differential to each area are then applied against the EIA forecast of the Henry Hub prices.

West RSG study will be a multi-year study. The base case is set at year 2020. Starting from the 2011 fuel forecast in the Powerbase, we scaled the gas price within MAPPMAIN footprint to $9.00/mmBtu. As we added new coal plants into the CAPX study the coal price used is $1.77/mmBtu. All the new coal plants should run at a 60% and above

[3] Platts Fuel Forecasting methodology, found on NEA PowerBase support web site

capacity factor range. Based on this assumption, the Boswell Energy Center Coal price is set as $1.77/mmBtu and all other coal prices are adjusted accordingly.

LOAD FORECAST

The CAPX companies provided the 2020 load forecast for the following control areas: ALTW, NSP, MP, SMMP, GRE, OTP and DPC. In PROMOD, there are two companies within the OTP control area: Otter Tail Power Co. and Minnkota Power Coop. The load forecast for OTP control area is then distributed to two companies respectively. The detailed load forecast for all CAPX companies are listed in Table 32. Other companies' load forecast stay as 2011 load forecast from Powerbase.

Table 32

	Peak Load at 2020 (MW)	Annual Energy in 2020 (GWH)
GRE	3894	19677.3
ALWST	3888.2	19728.2
DPC	1266.2	6675.0
MPL	1814.4	12674.0
NSP	12885.1	67017.6
SMMP	442.4	2512.8
MPC	1080.8	7048.4
OTP	1167.5	6844.0
Total	26438.6	142177.3

GENERATING UNITS AND PARAMETERS

Existing Units

Typically as a part of PROMOD model development process, MISO verifies generators in the default Powerbase database against the MISO loadflow models. Stakeholders are involved in this process: Expansion Planning Working Group (reporting to Planning Sub-Committee) is sent a list of generators mapped to load flow models and member comments are solicited. Different Regional Study Groups (RSG) are also involved at times. MISO has 3 RSG's: Central, East and West modeled according to the Operation regions. For the CAPX study the West RSG helped verify generators in the CAPX study area.

New units for West RSG study

To serve the increased load in West RSG area (around 6000MW load increase), Generation Interconnection requests submitted in MISO queue are recommended as a generation scenario. These requests are distributed in West region (except Wisconsin), and the total capacity is 6689 MW, in which 2948 MW is renewable resource. All new generators are created from the similar existing generators in Powerbase, with the fuel set as $1.77/mmBtu for coal generators and $9.00/mmBtu for Gas turbine. The detailed list of new generators can be found in Appendix B.

TRANSMISSION UPGRADES

West RSG study is based on MTEP06 Phase 2 power flow model. In corresponding to the new generation/load increase, the following transmission upgrades are added, which are based on the recommended facilities from several studies in West region.

- Big Stone II interconnection/delivery upgrades (Alternative 1)
- Common facility upgrades recommended both in Minnesota and North/West bias scenarios in CapX 2020, Boswell-Wilton 230kV line is also included;
- Facility upgrades recommended in Buffalo Ridge Incremental Generation Outlet (BRIGO) study;
- Facility upgrades recommended in Southwest Minnesota to Twin Cities EHV Development study;
- Facility upgrades recommended in Southeastern Minnesota – Southwestern Wisconsin Reliability Enhancement Study;
- Some facility upgrades recommended in ATC Access project study, including Paddock-Rockdale project (P-R), LaCrosse-Columbia project (portion of Prairie Island-Columbia), and Salem-North Madison (S-NM) project.
- Some facility upgrades recommended in Iowa-Southern Minnesota exploratory study, including Hazelton-Salem, Salem-Nelson Dewey-Spring Green 345 kV lines.

The line list for these projects can be found in Table 33.

Table 33: New Transmission Lines in West RSG Study

From	To	kV	Miles	Comments
Alexandria	Monticello	345		CapX
Alexandria	Maple River	345	126	CapX
Antelope Valley	Maple River	345	292	CapX
Arrowhead	Chisago	345	120	CapX
Arrowhead	Forbes	345	60	CapX
Benton County	Chisago County	345	59	CapX
Benton County	Granite Falls	345	110	CapX
Benton County	St. Boni	345	62	CapX
Blue Lake	Ellendale	345	200	CapX
Chisago County	Prairie Island	345	82	CapX
Columbia	N. LaCrosse	345	80	CapX, ATC
Ellendale	Hettinger	345	231	CapX
Rochester	N. LaCrosse	345	60	CapX, ATC, SE_MN-SW_WI, ISMN
Prairie Island	Rochester	345	58	CapX, ATC, SE_MN-SW_WI, ISMN
Boswell	Wilton	230		CapX
Big Stone	Ortonville	230		BS II
Ortonville	Johnson Jct.	230		BS II
Johnson Jct.	Morris	230		BS II
Big Stone	Canby	230		BS II
Canby	Granite Falls	230		BS II
Alexandria		345/115		CapX
Alex	Sauk Ct	115	25	CapX
Sauk Ct	Melrose	115	10	CapX
Melrose	Albany	115	15	CapX
Albany	W. St. Cloud	115	25	CapX
Lk Yankton	Marshall	115		BRIGO
Nobles	Fenton	115		BRIGO
Nobles	Nobles	345/115		BRIGO
Marshall SW Sub				MRES
Brookings Co	Lyon Co	345		CAPX (SW_MN-TC)
Lyon Co	Franklin	345	double	CAPX (SW_MN-TC)
Franklin	Helena	345	double	CAPX (SW_MN-TC)
Helena	Lk Marion	345		CAPX (SW_MN-TC)
Lk Marion	Hampton Corner	345		CAPX (SW_MN-TC)
Lyon Co	Hazel	345		CAPX (SW_MN-TC)
Brookings Co	Yankee	115		CAPX (SW_MN-TC)
Brookings Co	Toronto	115		CAPX (SW_MN-TC)
Hazelton	Salem	345	70	ISMN
Salem	N Madison	345		ATC, ISMN
Paddock	Rockdale	345		ATC
Lakefield	Winnebago	345		ISMN
Winnebago	Hayward	345		ISMN
Hayward	Adams	345		ISMN

APPENDIX B - WEST RSG STUDY NEW GENERATING UNITS

MISO Project Num	Bus numb	Bus name	Pmax	Pmin	Qmax	Qmin	MISO Queue Date	Control Area	County	State	In Service Date	Study Status	IA Status	Project manager	Interconnection Service Type	Fuel Type
NE group																
G424	61710	MINNTAC7	100	0	0.00	0.00	19-Apr-04	MN	St. Louis	MN	01-Dec-06	FEC SIC FE		Diwakar Tewari	ER	Wind
G509	61705	BABBITT7	75	0	0.00	0.00	18-Mar-05	MP	St. Louis	MN	01-Aug-06	FEC SIE		Diwakar Tewari	NR	Wind
G519	61625	BLCKBRY4	580	0	190.64	-190.64	19-May-05	MP	Itasca	MN	01-Apr-09	SIE		Diwakar Tewari	NR	Coal and/or a blend of Petroleum coke and coal
G591_592	60101	FORBES 2	800	0	262.95	-262.95	25-Jan-06	MP	St. Louis	MN	01-Mar-13	FEP		Raja Srivastava	NR	Coal
G597	61625	BLCKBRY4	606	0	199.18	-199.18	14-Feb-06	MP	Itasca	MN	01-Jan-13	FEP		Ron Arness	NR	Coal
G600	63254	VIKING 7	110	0	0.00	0.00	16-Feb-06	OTP	Marshall	MN	31-Dec-08	FEP		Ron Arness	ER	Wind
ND group																
G380	63279	RUGBOTP7	150	0	0.00	0.00	21-Nov-03	OTP	Pierce	ND	01-Dec-05	IC/FC	IAF	Kun Zhu	ER	Wind
G531	63049	STANTON4	80	0	26.29	-26.29	01-Jul-05	GRE	Mercer	ND	01-Apr-09	SIE		Raja Srivastava	NR	Coal
G581	66791	CENTER 3	600	0	197.21	-197.21	27-Dec-05	MP	Oliver	ND	01-Jan-15	FEP		Raja Srivastava	NR	Coal
G607	67316	COYOTE 3	25	0	8.22	-8.22	01-Mar-06	OTP	Mercer	ND	25-Oct-08	FEP		Ron Arness	NR	Coal
Group 4																
G389	63043	ELK RIV4	200	0	65.74	-65.74	03-Nov-03	GRE	Sherburne	MN	01-Jan-07	IP		Raja Srivastava	NR	Natural Gas
G390	63043	ELK RIV4	100	0	32.87	-32.87	03-Nov-03	GRE	Sherburne	MN	01-Jan-09	IP		Raja Srivastava	NR	Natural Gas
G417	60896	SHAKOPE8	15	0	4.93	-4.93	22-Mar-04	NSP	Scott	MN	31-Dec-05	IP		Raja Srivastava	NR	biomass
G474	63220	ELBOWLK7	20	0	0.00	0.00	01-Oct-04	OTP	Grant	MN	01-Nov-05	IP		Raja Srivastava	NR	Wind
G489	60119	LKYNKTN7	20	0	0.00	0.00	19-Jan-05	NSP	Lyon	MN	01-Oct-06	IP		Raja Srivastava	NR	Wind
G491	60715	CHANRMB9	150	0	0.00	0.00	29-Dec-04	NSP	Pipestone	MN	01-May-07	FEP		Raja Srivastava	NR	Wind
G502	66752	DRAYTON4	50	0	0.00	0.00	14-Mar-05	MP	Oliver	ND	01-Nov-05	SIC FE		Raja Srivastava	NR	Wind
G514	60331	LKFLDXL3	200	0	0.00	0.00	20-Apr-05	NSP	Jackson	MN	01-Oct-06	FEE		Raja Srivastava	NR	Wind
G517	34226	STORDEN8	150	0	0.00	0.00	02-May-05	ALTW	Cottonwood	MN	01-Oct-06	SIE		Raja Srivastava	NR	Wind
G518	62371	WLKFLTP	8	0	0.00	0.00	02-May-05	GRE	Jackson	MN	01-Nov-06	FE		Raja Srivastava	NR	Wind

MISO Project Num	Bus numb	Bus name	Pmax	Pmin	Qmax	Qmin	MISO Queue Date	Control Area	County	State	In Service Date	Study Status	IA Status	Project manager	Interconnection Service Type	Fuel Type
G520	60119	LKYNKTN7	150	0	0.00	0.00	20-May-05	NSP	Lyon	MN	31-Dec-06	SIE		Raja Srivastava	NR	Wind
G530	34164	GR JCT 9	14	0	0.00	0.00	15-Jun-05	ALTW	Greene	IA	01-Sep-06	IP		Raja Srivastava	NR	Wind
G532	62792	ODIN	19.95	0	0.00	0.00	06-Jul-05	ALTW	Cottonwood /Watonwan	MN	01-Sep-06	IP		Raja Srivastava	NR	Wind
G536	62371	WLKFLTP	20	0	0.00	0.00	20-Jul-05	ALTW	Jackson	MN	01-Oct-06	SIE		Raja Srivastava	NR	Wind
G538	34137	TRIBOJI5	150	0	0.00	0.00	08-Aug-05	ALTW	Dickinson	IA	01-Oct-06	FEP		Raja Srivastava	NR	Wind
Group 5																
G540	34015	LIME CK5	80	0	0.00	0.00	01-Sep-05	ALTW	Worth	IA	31-Dec-07				NR	Wind
G548	34015	LIME CK6	80	0	0.00	0.00	17-Sep-05	ALTW	Worth	IA	31-Dec-06				NR	Wind
G551	34371	RICE 8	100	0	0.00	0.00	27-Sep-05	ALTW	Howard	IA	01-Sep-07				NR	Wind
G552	62053	MAPLE H8	50.4	0	0.00	0.00	28-Sep-05	ALTW	Emmet	IA	01-Aug-06				NR	Wind
G555	66555	MORRIS 7	100	0	0.00	0.00	24-Oct-05	OTP	Stevens	MN	01-Nov-07				NR	Wind
G573	64239	FRANKLN5	80	0	0.00	0.00	09-Dec-05	ALTW	Franklin	IA	01-Oct-06				NR	Wind
G574	64239	FRANKLN6	80	0	0.00	0.00	09-Dec-05	ALTW	Franklin	IA	30-Sep-07				NR	Wind
G575	64239	FRANKLN7	40	0	0.00	0.00	09-Dec-05	ALTW	Franklin	IA	01-Oct-06				NR	Wind
G576	60128	SPLT RK5	40	0	0.00	0.00	12-Dec-05	GRE	Rock	MN	01-Sep-07				ER	Wind
G586	60050	YANKEE 1	30	0	0.00	0.00	30-Dec-05	NSP	Lincoln	MN	01-Jun-07				NR	Wind
G587	60728	FRANKLN8	20	0	0.00	0.00	30-Dec-05	NSP	Sibley	MN	01-Jun-07				NR	Wind
G589	34018	HAZLTON3	750	0	246.51	-246.51	12-Jan-06	ALTW	Black Hawk	IA	01-Dec-09				NR	Coal
G593	34007	LAKEFLD5	100	0	0.00	0.00	07-Feb-06	ALTW	Jackson	MN	01-Oct-07				NR	Wind
G594	62369	ROUND LK	50	0	0.00	0.00	07-Feb-06	GRE	Jackson	MN	01-Oct-07				NR	Wind
G595	34139	HANCOCK5	210	0	0.00	0.00	13-Feb-06	ALTW	Hancock	IA	30-Jul-07				ER	Wind
G602	60369	FENTON	31.5	0	0.00	0.00	23-Feb-06	NSP	Nobles	MN	01-Nov-07				NR	Wind
G604	62886	OWATONNA	47.5	0	0.00	0.00	27-Feb-06		Steele	MN	01-Nov-06				ER	Wind
G608	60760	PAYNES8	6.3	0	0.00	0.00	02-Mar-06		Pope	MN	01-Oct-06				ER	Wind
G612	34071	FERNALD7	150	0	0.00	0.00	20-Mar-06	ALTW	Story	IA	31-Aug-07				ER	Wind
G614	34008	FOX LK5	250	0	0.00	0.00	24-Mar-06	NSP	Emmet/Dic kinson	IA	01-Jul-07				NR	Wind
Exira #3	67469	EXIRA 3G	40	0				MRES			1-Jun-07					Gas

APPENDIX C – METHOD FOR CONVERTING WIND SPEED DATA TO WIND GENERATION

Meteorological simulations for creating chronological wind speed data has greatly enhanced the value of wind integration studies. It is not possible to generate a separate wind speed profile for each turbine in the wind generation scenario. Each profile, therefore, must represent a number of turbines located in the general vicinity of the model extraction point.

The objective of this exercise is to determine a method for calculating hourly wind generation from the measured wind data. The turbine power curve from Figure 56 is used.

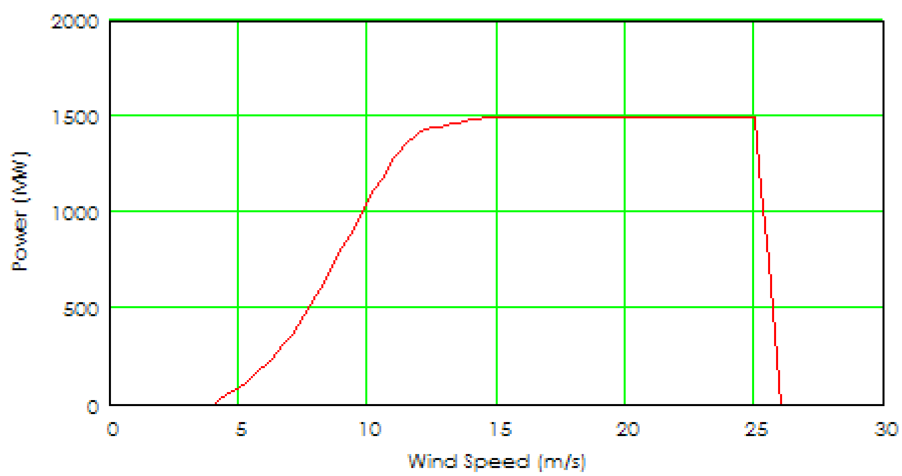

Figure 56: Turbine power curve used for calculating generation data from wind speed measurements.

Measurement data from an operating wind plant with 30 of the turbines referenced above, consisting of wind speed and plant power at ten minute intervals was processed to create a "plant" power curve. This curve is shown in Figure 57.

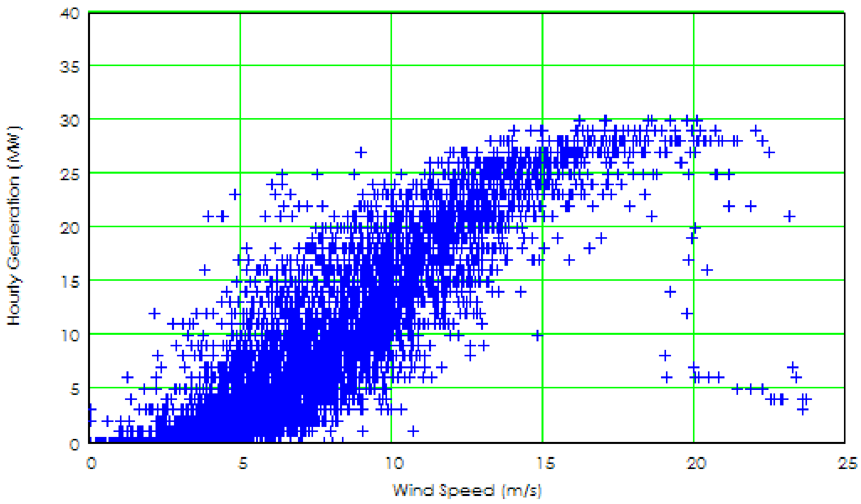

Figure 57: Empirical "Power Curve" for wind plant from measured values.

Figure 58 shows the results of applying the power curve from Figure 56 (scaled appropriately) to 10-minute wind speed data, then aggregating the results to hourly average values. The striking feature of this figure is the "fuzziness." If the wind speed data were averaged to hourly values before applying the power curve, the characteristic would match that shown in Figure 56: Turbine power curve used for calculating generation data from wind speed measurements.. The difference, of course, is that the mathematical operations are not the same because of the nonlinear nature of the turbine power curve.

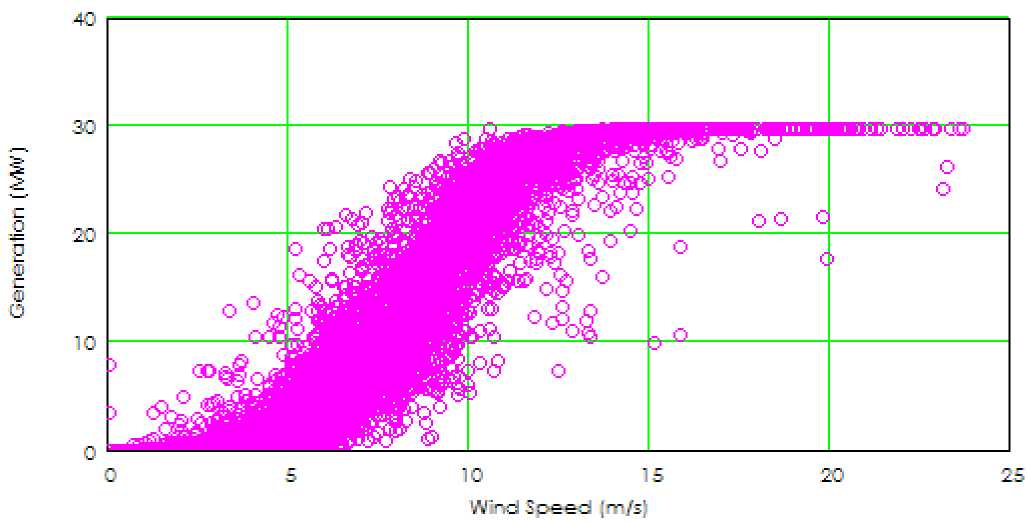

Figure 58: Wind plant "power curve" calculated from 10-minute wind speed values.

A closer comparison (Figure 59) of the calculated and measured wind generation reveals that the simple transformation from wind speed to power using a single power curve and wind speed value leads to a calculated value that is higher than the actual, and a tendency to "saturate" during periods of high wind, sometimes unlike the measured data. A computation of the energy delivered shows that the calculated value is about 25% higher than what was actually metered.

Figure 60 illustrates this qualitatively. The "knee" of the calculated plant power curve is much more pronounced, although the "fit" is reasonable at lower power levels. Therefore, shifting the plant power curve to the right to approximately account for the diversity of wind speeds over the plant area would degrade the fit at lower wind speed levels.

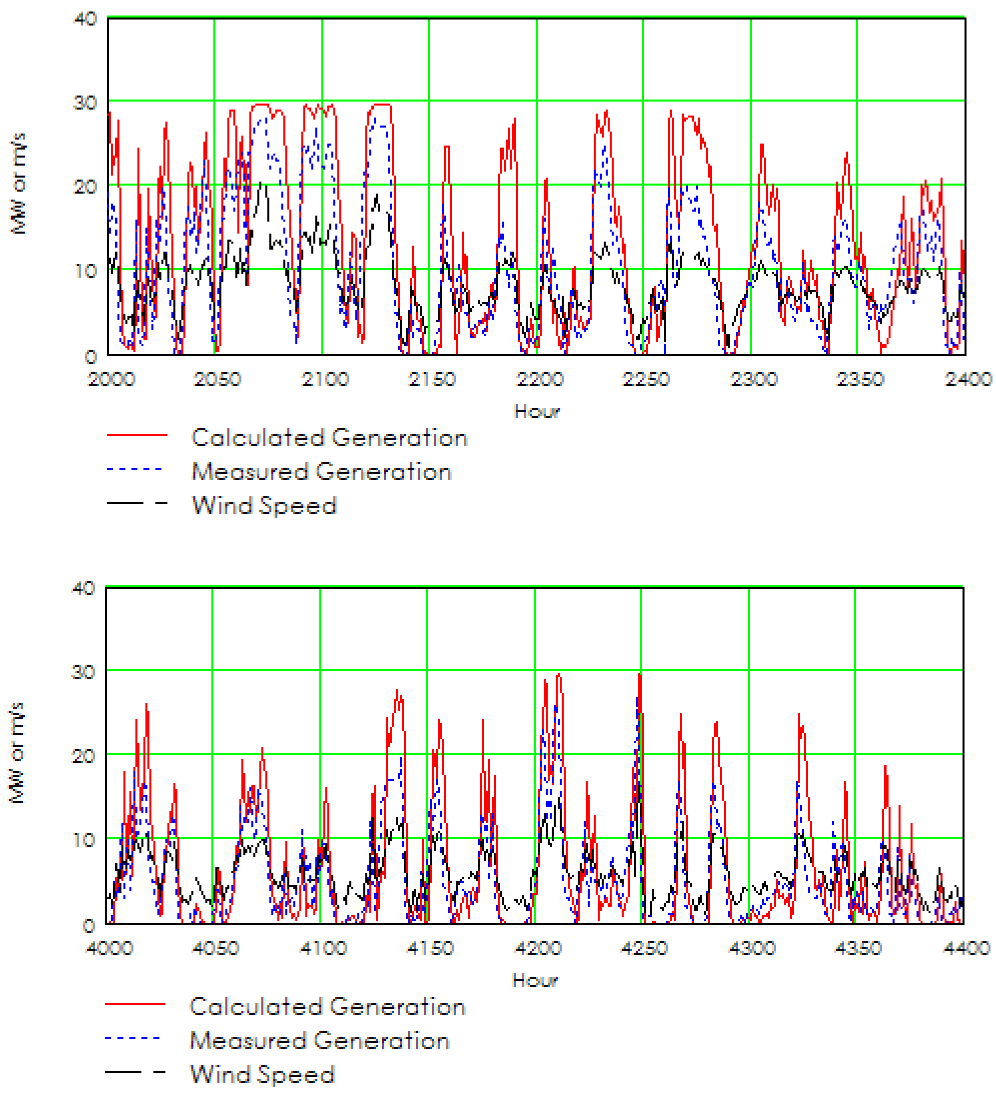

Figure 59: Calculated vs. Measured wind generation.

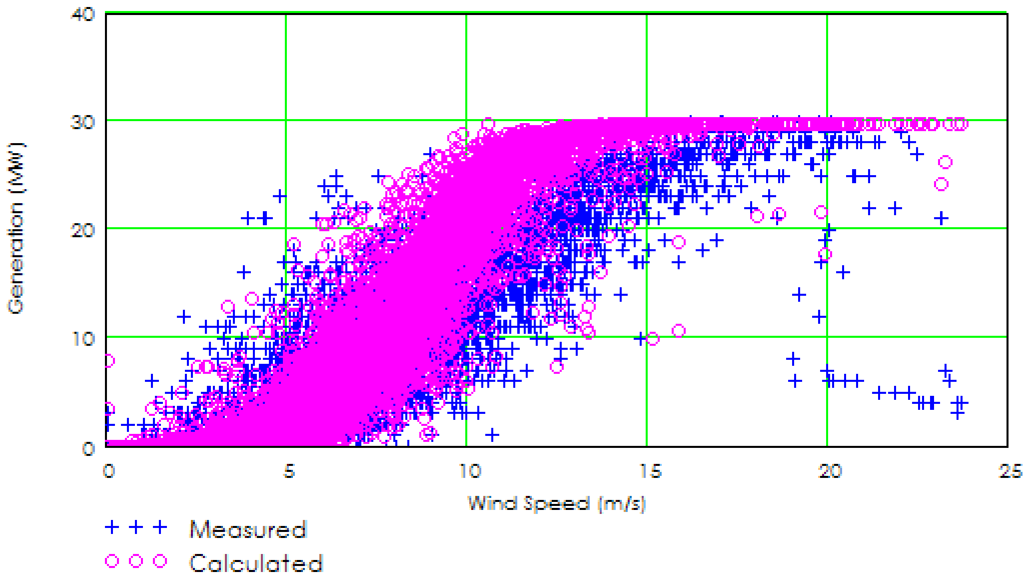

Figure 60: Measured and calculated plant power curves.

A better fit between the calculated and measured plant power curves (as well as the time series data) can be achieved by modifying the measured wind speed prior to applying the power curve. The modification consists of applying an exponent slightly less than one to the measured wind speed value. Figure 61 illustrates this for an exponent of 0.95. Note that the effect on low values of wind speed is much smaller than for larger ones. Also, for values well above the rated turbine wind speed, the modification makes no difference in the power calculation.

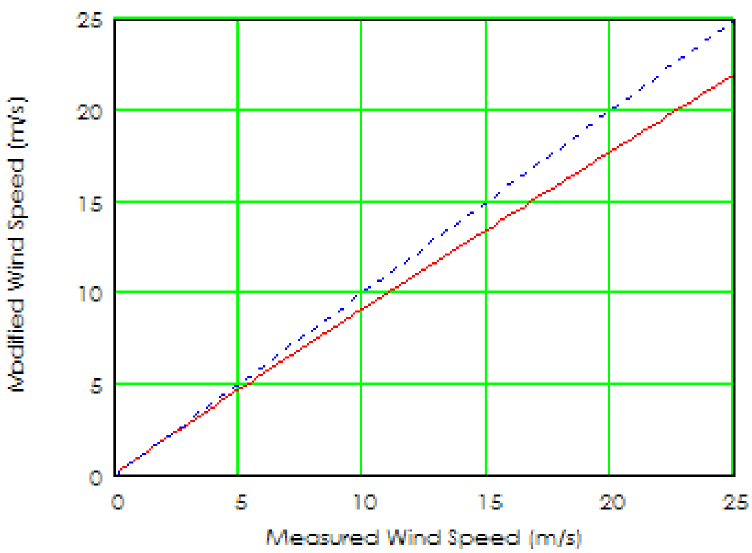

Figure 61: Exponential modification of measured wind speed.

The comparison of measured and actual power curves using this modification is shown in Figure 62. The calculated energy over the entire year for the calculated data differs by less than 1% from the measured data.

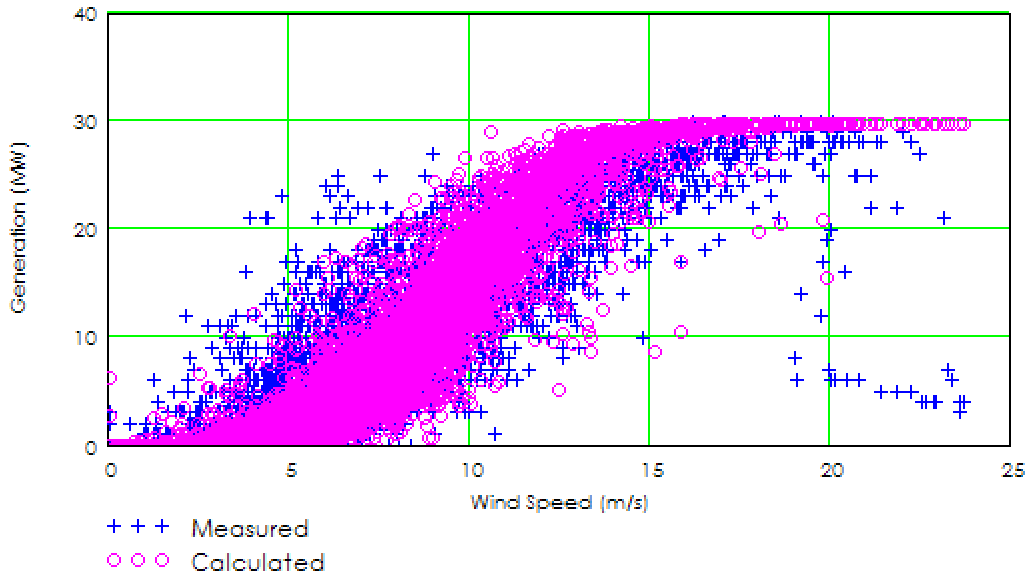

Figure 62: Measured and modified calculated plant power curves.

The improvement is also evident in the time series data. Figure 63 shows the same time periods from Figure 59, with the calculated value here based on a modified wind speed value. The improvement over the very simplified method using just the single turbine power curve is evident.

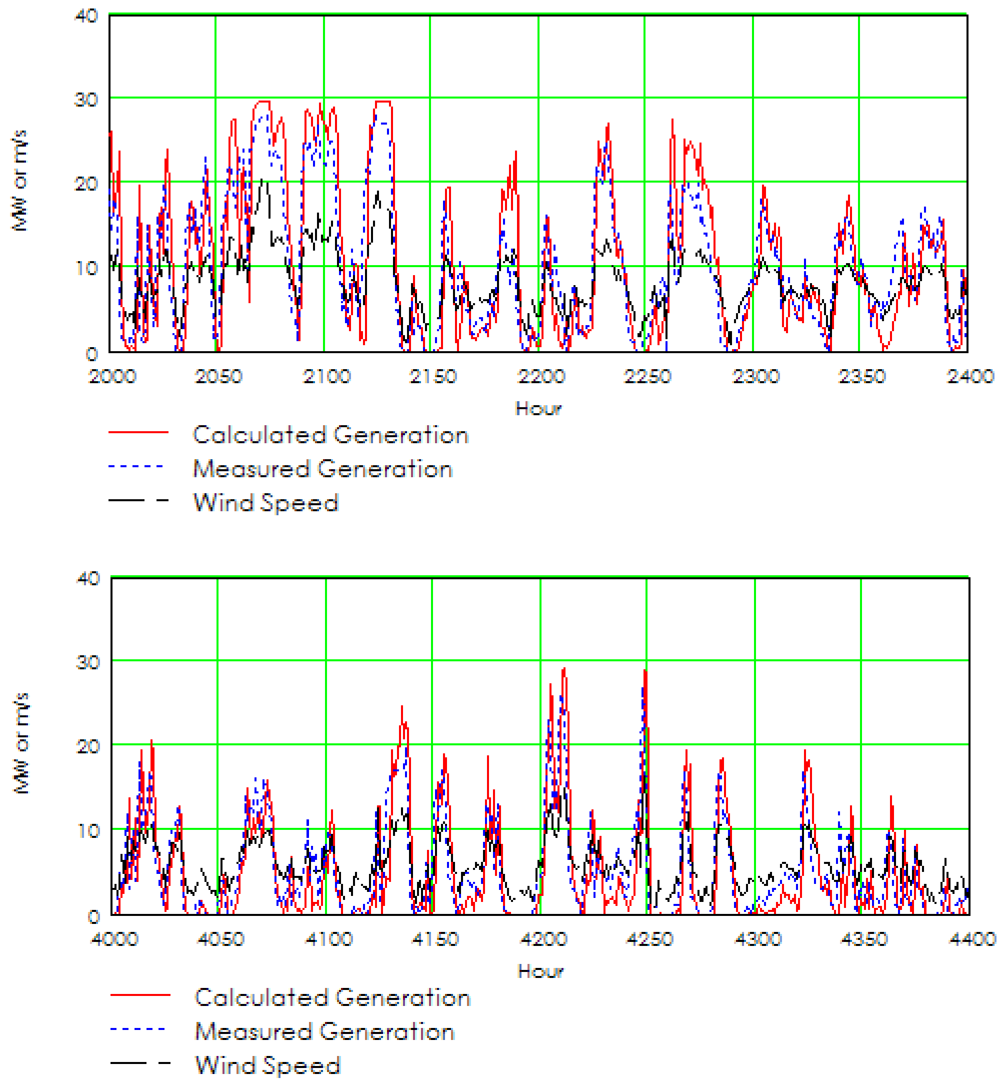

Figure 63: Comparison of measured wind generation to that calculated with wind speed modification.

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Areas With Highest Wind Share

Country/ Region	Installed Wind Capacity (2002)	Total Installed Power Capacity	Average Annual Penetration Level	Peak Penetration Level
Western Denmark:[3]	2,315 MW	7,018 MW	~ 18 %	**> 100 %**
Thy Mors	~ 40 MW	Part of the Western Danish System	>50 %	**~ 300 %**
Germany:	12,000 MW	119,500 MW	~ 5 %	
Schleswig Holstein	1,800 MW	Part of the German System	~ 28 %	**> 100 %**
Papenburg	611 MW	Part of the German System	~ 55 %	**> 100 %**
Spain:	5,050 MW	53,300 MW	~ 5 %	
Navarra	550 MW	Part of the Spanish System	~ 50 %	**> 100 %**
Island Systems:				
Swedish Island of Gotland	90 MW	No Local Generation in normal state	~ 22 %	**> 100 %**
Creak Island of Crete	70 MW	640 MW	~ 10 %	N. A.
Wind-Diesel System Denham, Australia	690 kW	2,410 kW	~ 50 %	**~ 70 %**

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Wind Energy Targets

	Germany	**Denmark (W+E)**	**Spain**	**Ireland**
Targets GW [Year]	50.3 [2020]	**3.6+1.2 [2020]**	13.0 [2011]	1.0 [2010]
Max. Penetration Level with Constant Interconnection Capacity	92 %	**W: 92 % E: 36 %**	75 %	46 %
For Comparision today's max. penetration level with Intercon. Cap.	30 %	**W: 61,5 % E: 21,2%**	45 to 48 %	14 %

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