Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States

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European Wind Energy Conference
Athens, Greece

February 27 – March 2, 2006

NREL/PR-500-39524

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Acknowledgements

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Brett Oakleaf, Xcel Energy

Kenneth Wolf, Minnesota Public Utilities Commission

Matt Schuerger, Energy Systems Consulting Services, LLC

Robert Zavadil, Enernex Corporation

Mark Ahlstrom, WindLogics

Dora Yen Nakafuji, California Energy Commission

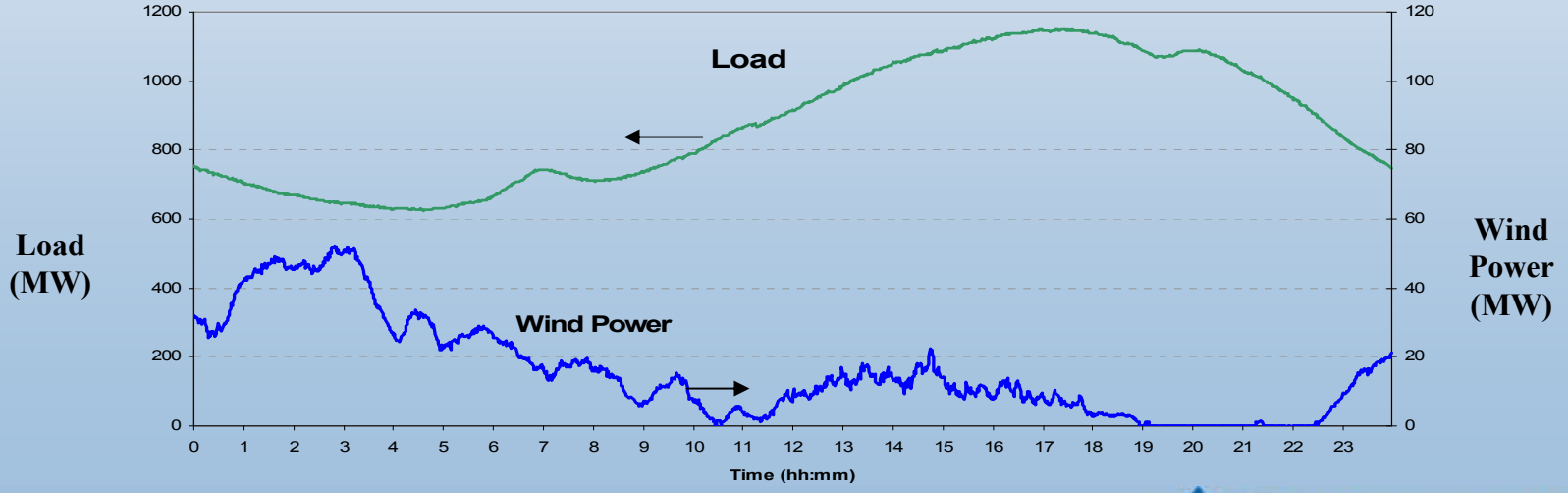
Critical review/input from Nicholas Miller and Richard Piwko of GE Energy, Kevin Porter, Exeter Associates, and Henry Shiu, University of California, Davis

Presentation Outline

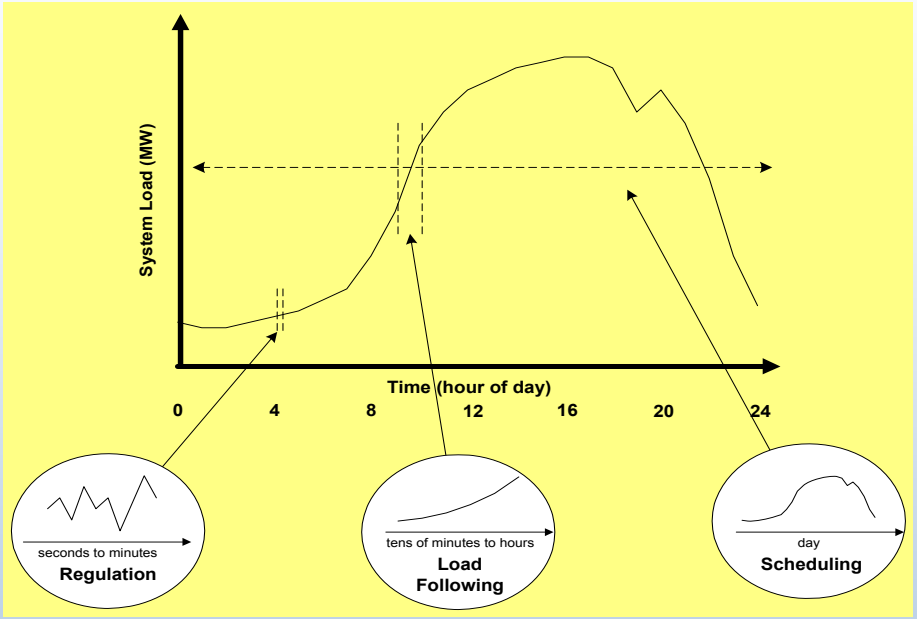
- Issues and time frames of importance
- Methods and approaches
- Four recent studies
  - Minnesota DOC/Xcel North
  - NYSERDA/GE New York State
  - Xcel Colorado
  - California Multiyear RPS Integration Cost Study
- Comparison with previous studies
- Conclusions and remaining issues
- Ongoing/future work

Wind Variability
Can Increase Power System Operating Costs

- Committing unneeded generation
- Allocating extra load-following capability
- Allocating additional regulating capacity
- Increased cycling operation
- **These are reflected in *ancillary services* costs**



Wind Variability
Power System Operation Impacts



Typical U.S. terminology

- Regulation -- seconds to a few minutes -- similar to variations in customer demand
- Load-following -- tens of minutes to a few hours -- demand follows predictable patterns, wind less so

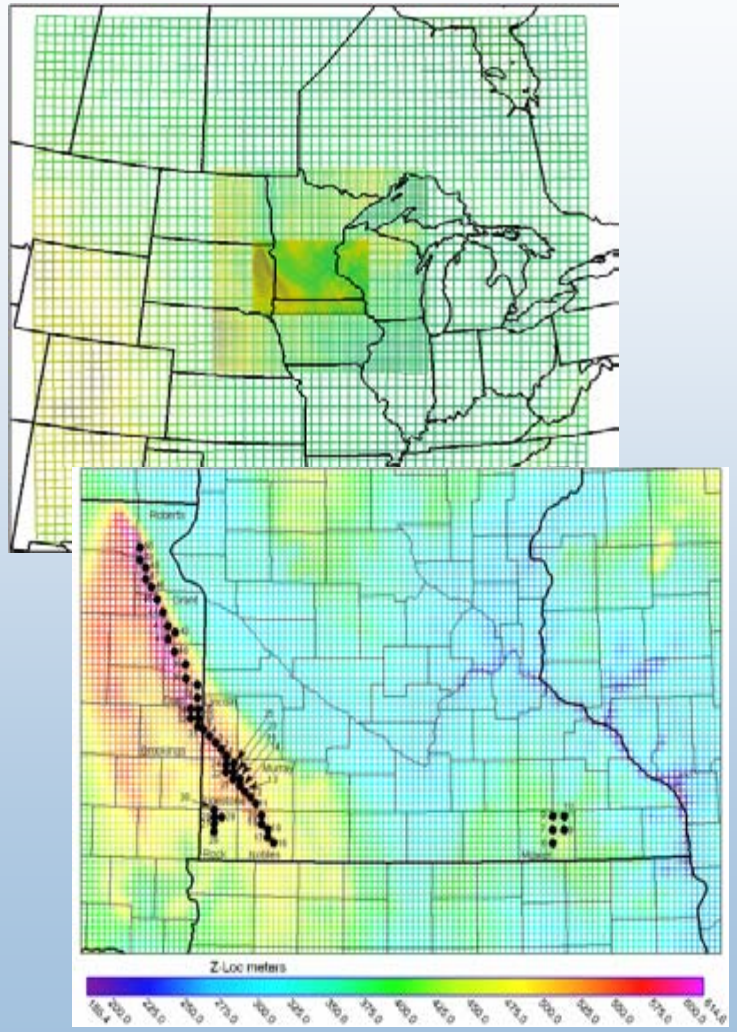
- Scheduling and commitment of generating units -- hours to several days -- wind forecasting capability?

Methods
Emerging Best Practices

- Capture system characteristics and response through operational simulations and modeling
- Capture wind deployment scenario geographic diversity through synchronized weather simulation
- Couple with actual historic utility load and load forecasts
- Use actual large wind farm power statistical data for short-term regulation and ramping
- Examine wind variation in combination with load variations
- Utilize wind forecasting best practice and combine wind forecast errors with load forecast errors
- Examine actual costs independent of tariff design structure

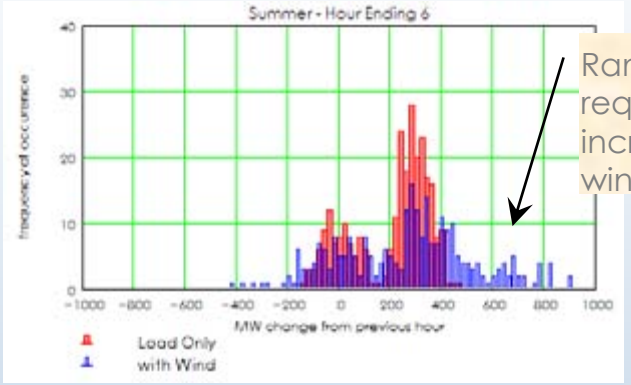
Minnesota Dept. of Commerce/ Enernex Study Framework

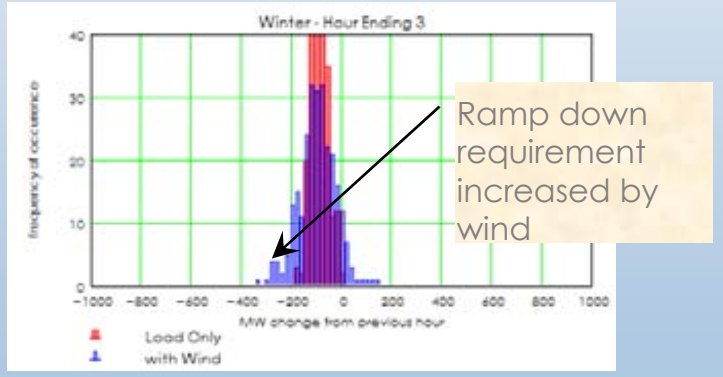
- 2010 scenario of 1500 MW of wind in 10 GW peak load system (< 700 MW wind currently)
- WindLogics:10-minute power profiles from atmospheric modeling to capture geographic diversity
- Wind forecasting incorporated
- Extensive historic utility load and generator data available
- Monopoly market structure, no operating practice modification or change in conventional generation expansion plan



Minnesota Dept. of Commerce/ Enernex Study Results

- Incremental regulation due to wind 3σ = 8 MW
- Incremental intra-hour load following burden increased 1-2 MW/min. (negligible cost)
- Hourly to daily wind variation and forecasting error impacts are largest costs
- Monthly total integration cost: $2-$11/MWh, with an average of $4.50/MWh
- Capacity Credit (ELCC) of 26%

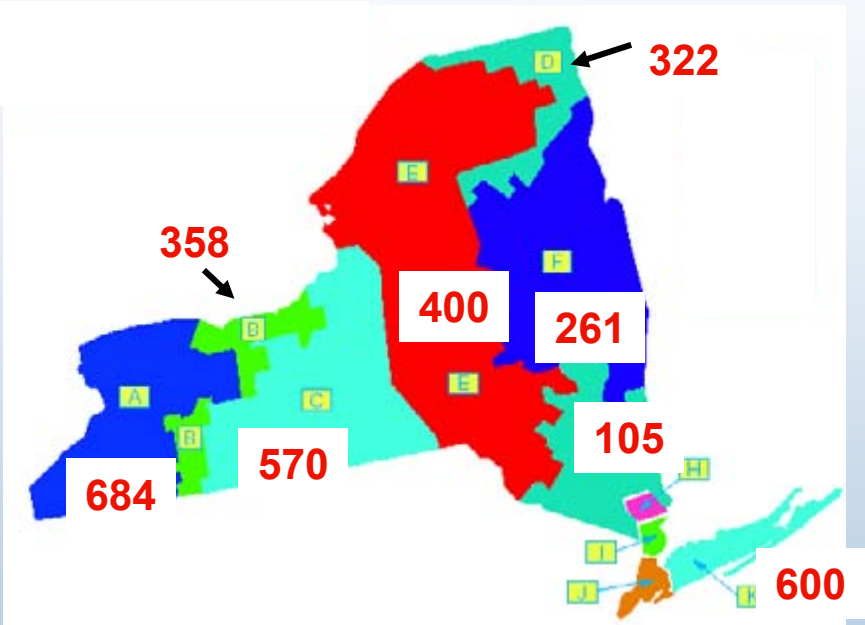




Completed September 2004 *www.commerce.state.mn.us*
(Industry Info and Services / Energy Utilities / Energy Policy / Wind Integration Study)

New York ISO and NYSERDA/ GE Energy Study

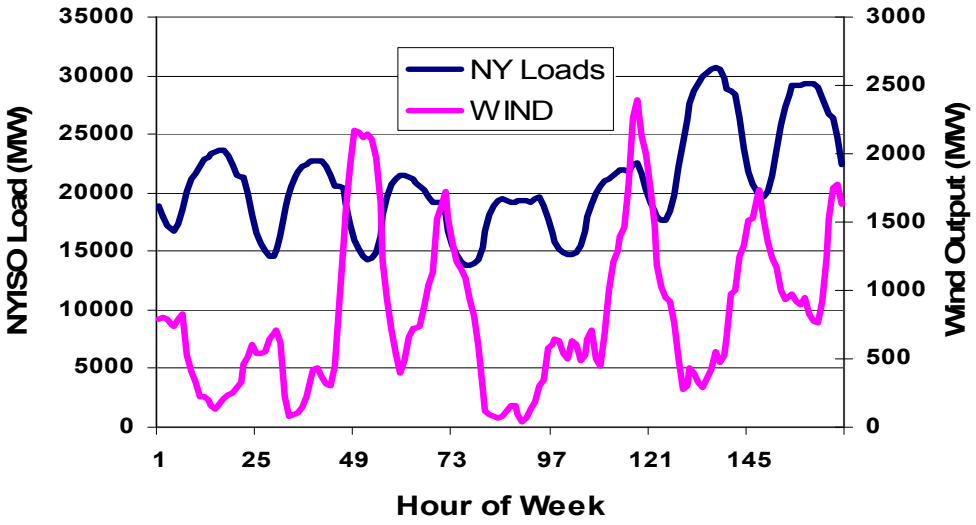
- 2008 scenario of 3300 MW of wind in 33-GW peak load system (< 200 MW wind currently)
- AWS Truewind: wind power profiles from atmospheric modeling to capture statewide diversity



- Competitive market structure:
  - for ancillary services
  - allows determination of generator and consumer payment impacts
- Transmission examined: no delivery issues
- Post-fault grid stability improved with modern turbines

New York ISO and NYSERDA/ GE Energy Study Impacts

- Incremental regulation of 36 MW due to wind
- No additional spinning reserve needed
- Incremental intra-hour load following burden increased 1-2 MW/ 5 min.
- Hourly ramp increased from 858 MW to 910 MW



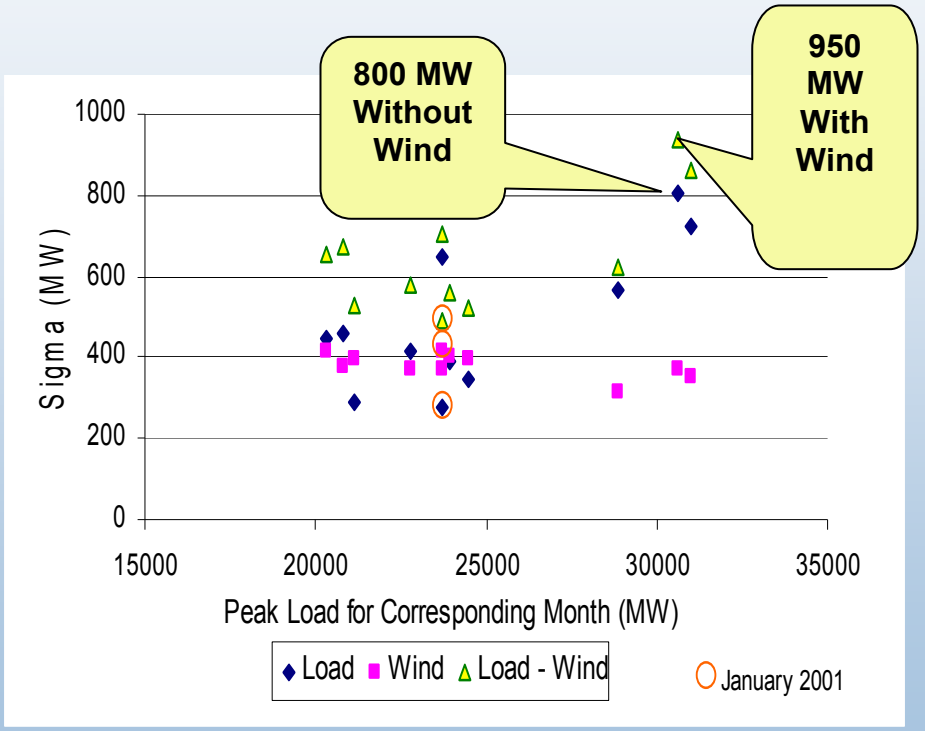
- All increased needs can be met by existing NY resources and market processes
- Capacity credit (UCAP) of 10% average onshore and 36% offshore
- Significant system cost savings of $335- $455 million on assumed 2008 natural gas prices of $6.50-$6.80 /MMBTU.

New York ISO and NYSERDA/ GE Energy Study

Forecasting and Price Impacts

- Day-ahead unit-commitment forecast error σ increased from 700-800 MW to 859-950 MW
- Total system variable cost savings increases from $335 million to $430 million when state of the art forecasting is considered in unit commitment ($10.70/MWh of wind)
- Perfect forecasting increases savings an additional $25 million

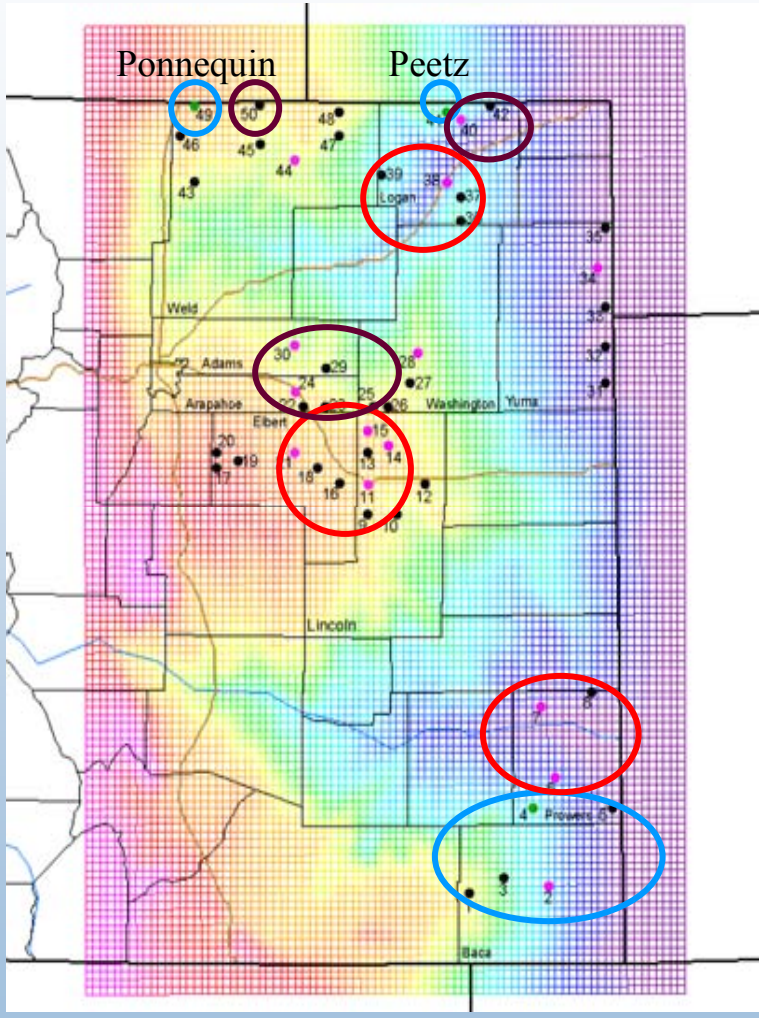
Standard Deviations of Day-Ahead Forecast Errors



http://www.nyserda.org/publications/wind_integration_report.pdf

Xcel Colorado/Enernex Study

- 10%, 15%, and 20% penetration (wind nameplate to peak load) examined for ~7 GW peak load
- Gas storage & nominations
  - Gas imbalance
  - Extra gas burn for reserves
- Gas price sensitivity
- Transmission constraints
- O&M increase for increased start/stops
- Real-time market access



Xcel Colorado/Enernex Study

Penetration Level	10%	15%	20%[2]
Hourly Analysis	$2.26/MWh	$3.32/MWh	$6.57/MWh
Regulation	$0.20/MWh	$0.20/MWh	$0.20/MWh
Gas Supply (1)	$1.26/MWh	$1.45/MWh	$2.10/MWh
Total	**$3.72/MWh**	**$4.97/MWh**	**$8.87/MWh[2]**

(1) Costs includes the benefits of additional gas storage
(2) Rough results based on scaling wind generation without geographic diversity benefits

- **Without cycling of 300 MW pumped hydro unit, costs at 10% would be $1.30/MWh higher**

Preliminary Results – pending final report anticipated in April 2006

Gas Storage Benefits/Results

- Summer/winter arbitrage
  - Cost savings in filling in summer and withdrawing in winter
- Reduction in need for financial hedge (call option)
  - Because the price of the gas in the storage field is known, there is no need to financially hedge the market price of the gas

Wind Penetration	10%	15%	20%
$/ MWH Gas Impact No Storage Benefits	$2.17	$2.52	$3.66
$ / MWH Gas Impact With Storage Benefits	$1.26	$1.45	$2.10

20% results based on scaling wind generation without geographic diversity benefits

CA RPS Integration Cost Project

- Examining impacts of existing installed renewables (wind 4% on a capacity basis)
- Calculated regulation, load following impacts of all renewables
- Capacity value (ELCC) for all renewables
- Regulation cost for wind $0.36/MWh (corrected)
- Load following: minimal impact
- Wind capacity credit 23%-25% of benchmark gas unit

http://cwec.ucdavis.edu/rpsintegration

CA RPS Lessons Learned

Data and Modeling Assumptions Matter

- Data from PI (power information) system
  - compression may artificially smooth high-resolution (fast) data
  - Missing data correction algorithm introduced artificial ramps in wind data
- Complex system influences wind capacity value
  - Scheduled maintenance of conventional generation
  - Hydro dispatch
  - Interchange schedule
- Multi-year analysis will be released by CEC any day now: regulation impacts similar to 1-year study, capacity value shows some fluctuation year-to-year, load following impact still difficult to detect

Comparison of Cost-Based U.S. Operational Impact Studies

Date	Study	Wind Capacity Penetration (%)	Regulation Cost ($/MWh)	Load Following Cost ($/MWh)	Unit Commitment Cost ($/MWh)	Gas Supply Cost ($/MWh)	Total Operating Cost Impact ($/MWh)
May '03	Xcel-UWIG	3.5	0	0.41	1.44	na	1.85
Sep '04	Xcel-MNDOC	15	0.23	na	4.37	na	4.60
July '04	CA RPS Phase III	4	0.36 (1)	na	na	na	na
June '03	We Energies	4	1.12	0.09	0.69	na	1.90
June '03	We Energies	29	1.02	0.15	1.75	na	2.92
2005	PacifiCorp	20	0	1.6	3.0	na	4.6
April '06	Xcel-PSCo	10	0.20	na	2.26	1.26	3.72
April '06	Xcel-PSCo	15	0.20	na	3.32	1.45	4.97
April '06	Xcel-PSCo (2)	20	0.20	na	6.57	2.10	8.87 (2)

(1) Represents corrected value
(2) Preliminary results based on scaling wind generation

Factors that Influence Results

- Balancing area size
  - Conventional generation mix
  - Load aggregation benefits
- Wind resource geographic diversity
- Market-based or self-provided ancillary services

Conclusions and Insights

- Additional operational costs are moderate for penetrations at or above portfolio standard levels
- For large, diverse electric balancing areas, existing regulation and load following resources and/or markets are adequate, accompanying costs are low
- Unit commitment and scheduling costs tend to dominate
- State of the art forecasting can reduce costs
  - majority of the value can be obtained with current state-of-the-art forecasting
  - additional incremental returns from increasingly accurate forecasts
- Realistic studies are data intensive and require sophisticated modeling of wind resource and power system operations

Some Remaining Issues

- Higher wind penetration impacts
- Effect of mitigation strategies
  - Balancing area consolidation and dynamic scheduling
  - Complementary generation acquisition (power system design) and interruptible/price responsive load
  - Power system operations practices and wind farm control/curtailment
  - Hydro dispatch, pumped hydro, other storage and markets (plug-hybrid electric vehicles, hydrogen)
- Integration of wind forecasting and real time measurements into control room operations

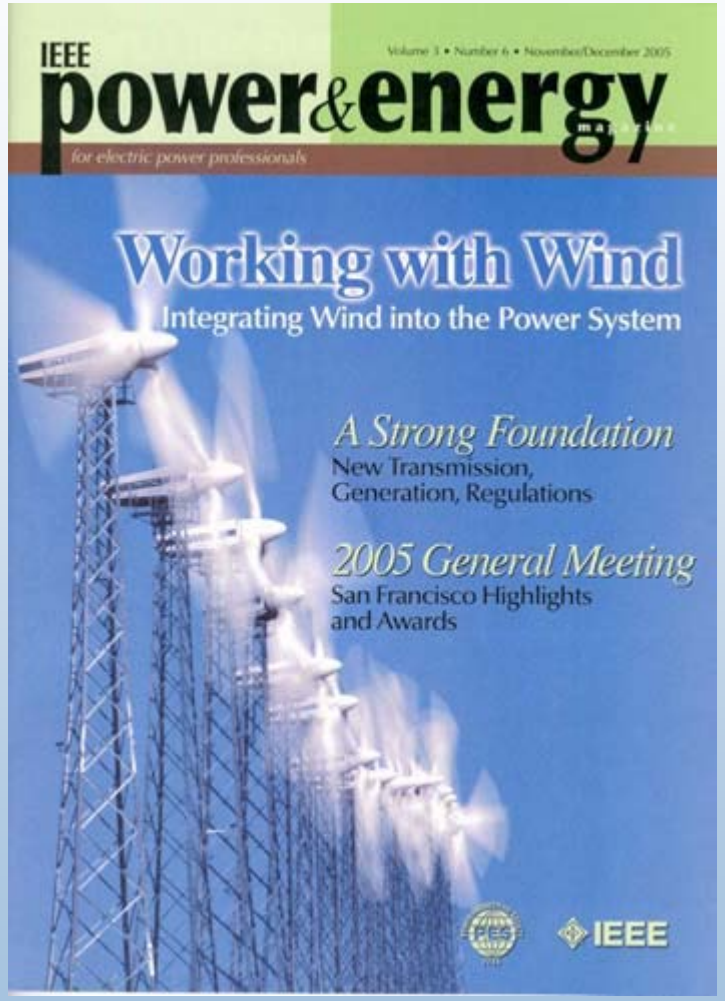
Future/Ongoing Work
(Enernex, WindLogics, Ariva, UWIG team)

- 2006 Minnesota Wind Integration Study
  - Statewide, 20% by *energy* (5 GW wind)
  - New MISO market structure
  - Examine transmission & mitigation strategies
  - Comparison of market operational and reliability rules
  - Completion date 11/06
- Xcel (MN) Renewable Development Fund: Control Room Integration of Wind
  - Define, design, build and demonstrate a complete wind power forecasting system for use by Xcel system operators
  - Optimize the way that wind forecast information is integrated into the control room environment
  - R&D on defensive operating strategies: Value of off-site met towers, high wind warning system, rapid update cycle (RUC) model

More Future/Ongoing Work

- California Energy Commission Intermittency Analysis Project
  - 5 GW of wind by 2010, up to >10 GW by 2020 (~15% by capacity)
  - Will consider whether mitigation measures are necessary at certain times (such as low load, high wind production)
  - Lead contractor: GE Energy with wind resource simulation by AWS Truewind
  - Completed by end of 2006
- Smaller balancing authority projects
  - Sacramento Municipal Utility District: high penetration, investigate value of pumped hydro
  - Public Service of New Mexico: limited conventional resources, high ramping wind, export and minimum load issues
  - Idaho Power and Grant County projects: integrate with constrained existing hydro

Increasing Attention in North America



- IEEE Power Engineering Society Magazine, November/December 2005
- Utility Wind Integration Group (UWIG): Operating Impacts and Integration Studies User Group
- www.uwig.org

UWIG
Utility Wind Integration Group

Accelerating the Integration of Wind Generation into Utility Power Systems