The Midwest Chapter of the Energy Bar Association
Announces its Fourteenth Annual Midwest Energy Conference

March 14-15, 2011

Conrad Hilton Indianapolis Hotel
50 West Washington Street
Indianapolis, Indiana
The American Recovery and Reinvestment Act of 2009 poured billions of federal taxpayer dollars into particular sectors of the electricity industry. However, what may have been intended for good has forced the industry and state regulators into a difficult position. Many of the “stimulus” programs come with conditions that would force state regulators to pass through significant costs to ratepayers, and the Department of Energy’s push to build out a high voltage grid overlay to facilitate the integration of wind resources has led to competing transmission planning arenas and the distortion of market signals. Now with the FERC’s proposed rulemaking on transmission planning and cost allocation potentially moving the country away from the Order 2000 minimum functions and characteristics of a regional market through inter-regional planning and the elimination of price signals via “economic” projects, reliance on regional transmission organizations is being called into question. Moreover, FERC’s proposed “public policy” approach to transmission planning – without any corresponding cost-benefit analysis – raises both legal and policy questions. This program will examine the state of the industry today as it copes with competing obligations, while seeking to ensure just and reasonable rates to consumers.

**PROGRAM SCHEDULE**

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<tr>
<th>Time</th>
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<tr>
<td>12:00 p.m.</td>
<td>OPTIONAL PRIMER</td>
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<tr>
<td>4:15 p.m.</td>
<td>Introduction to the Midwest ISO - A Primer for Lawyers</td>
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<td>The Midwest ISO is one of the nation’s largest regional transmission organizations. The development of its markets – and the overarching question of what value they provide – has been a major focus of activity in recent federal practice. This Primer will take place at the Midwest ISO’s facilities just north of Indianapolis in Carmel, and is oriented toward providing practical tips to the legal professional who is working with Regional Transmission Organization (RTO) issues. The Primer will include tours of the Midwest ISO’s control room, as well as a panel discussion of the Midwest ISO’s Value Proposition. Complimentary box lunches will be available, as well as shuttle transportation from the Midwest ISO to the Conrad Hilton Indianapolis.</td>
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<tr>
<td>5:30 p.m.</td>
<td>MIDWEST CHAPTER BUSINESS MEETING</td>
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<tr>
<td>5:45 p.m.</td>
<td>RECEPTION</td>
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<tr>
<td>9:30 a.m.</td>
<td>Rate Recovery Alternatives for New Power Plant Construction Projects</td>
</tr>
<tr>
<td>10:45 a.m.</td>
<td>NETWORKING BREAK</td>
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<tr>
<td>11:00 a.m.</td>
<td>Hot Topics - General Counsel</td>
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<tr>
<td>12:15 p.m.</td>
<td>Perspectives on Regional Transmission Organization Issues</td>
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**TUESDAY, MARCH 15, 2011**

<table>
<thead>
<tr>
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<tr>
<td>8:00 a.m.</td>
<td>REGISTRATION</td>
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<tr>
<td>8:30 a.m.</td>
<td>WELCOME AND INTRODUCTION</td>
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<tr>
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<td>Robert G. Mork</td>
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<td></td>
<td>President, Midwest Chapter of the Energy Bar Association</td>
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<td></td>
<td>Deputy Consumer Counselor for Federal Affairs</td>
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<td>Indiana Office of Utility Consumer Counselor</td>
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<td></td>
<td>Introduction: Susan N. Kelly</td>
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<td>President, Energy Bar Association</td>
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<td>American Public Power Association</td>
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Three Regional Transmission Organizations (RTOs) have important responsibilities for managing the transmission and energy systems throughout the Midwest, including planning, cost allocation, and reliability, and are confronting new challenges relating to environmental regulation and commodities trading. The General Counsels of the three RTOs will share their thoughts on these timely issues.

**Moderator:** The Honorable Monica Martinez
- Commissioner, Michigan Public Service Commission and President, Organization of MISO States
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<tr>
<td>12:15 p.m. -</td>
<td>LUNCHEON</td>
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<tr>
<td>1:30 p.m. -</td>
<td>Introduction: The Honorable James Atterholt Chairman Indiana Utility Regulatory Commission</td>
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<td>KEYNOTE SPEAKER</td>
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<td>The Honorable Tony Clark President, North Dakota Public Service Commission and President, National Association of Regulatory Utility Commissioners</td>
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<tr>
<td>1:30 p.m. -</td>
<td>Update on Eastern Interconnection Planning Process – Potential Impacts on the Midwest</td>
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<tr>
<td>2:45 p.m. -</td>
<td>NETWORKING BREAK</td>
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<td>The ARRA provided stimulus money for states and utilities to plan transmission eastern interconnection-wide. This panel will assess how the Eastern Interconnection Planning Collaborative (EIPC) and Eastern Interconnection States Planning Council (EISPC) processes are developing, what the goals are of the planning, what assumptions are used in the economic modeling scenarios, and what role NERC may play in the process. Do states really have a meaningful role in the planning process itself? Will planning for the entire interconnection result in Midwestern ratepayers rebuilding infrastructure for the east coast and Gulf Coast states? Is a public policy assessment and modeling criteria that only looks at benefits and neglects to assess costs valid? Is the emphasis on economic planning over reliability appropriate?</td>
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<td>Moderator: Robert A. Weishaar, Jr. Chair, Energy, Communications and Utility Law Group McNees Wallace &amp; Nurick LLC</td>
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<td>Panelists: Jeffrey R. Webb Senior Director - Expansion Planning Midwest ISO</td>
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<td>The Honorable Valerie A. Lemmie Commissioner, Public Utilities Commission of Ohio, and President of Organization of MISO States (2010)</td>
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<td>Mark G. Lauby Director, Reliability Assessments and Performance Analysis North American Electric Reliability Corporation (NERC)</td>
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<tr>
<td>3:00 p.m. -</td>
<td>A New World Order? How Gas and Renewable Generation May Soon Stack Up</td>
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<tr>
<td>4:45 p.m.</td>
<td>The underlying economics of generation is changing. The ARRA helped to fuel a big growth cycle for renewables, and a lame duck deal saw the extension of Section 1603 credits for another year. Even so, renewables’ defeat on a national Renewable Electricity Standard and the failure of cap and trade legislation may foreshadow some deterioration in policy support at the federal level. At the same time, natural gas discoveries in Marcellus and other deep shale formations – when combined with lower carbon emissions than with other fossil fuel generation – could revitalize interest in some gas plants that have not seen significant dispatch rates in several years. Will shifts in underlying economic assumptions soon change the mix in generation? What are the current merchant plant prospects for renewables and natural gas fired plants? Do the underlying shifts in economic factors reinforce or undermine related planning initiatives?</td>
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<td>Moderator: The Honorable David C. Boyd Chairman, Minnesota Public Utilities Commission</td>
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- Porter Wright
- Stewart & Irwin, PC
- Vectren

**Silver Associate**
- Freddi L. Greenberg
Panelists: Heather Starnes
Manager, Regulatory Policy
Southwest Power Pool, Inc.
Stephen G. Kozy
Vice President, General Counsel, and Secretary
Midwest Independent Transmission System Operator, Inc.
Vincent P. Duane
Vice President and General Counsel
PJM Interconnection, L.L.C.

12:15 p.m. - 1:30 p.m.
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Chairman
Indiana Utility Regulatory Commission

KEYNOTE SPEAKER
The Honorable Tony Clark
President, North Dakota Public Service Commission
and President, National Association of Regulatory Utility Commissioners

1:30 p.m. - 2:45 p.m.
Update on Eastern Interconnection
Planning Process – Potential Impacts on the Midwest

The ARRA provided stimulus money for states and utilities to plan transmission eastern interconnection-wide. This panel will assess how the Eastern Interconnection Planning Collaborative (EIPC) and Eastern Interconnection States Planning Council (EISPC) processes are developing, what the goals are of the planning, what assumptions are used in the economic modeling scenarios, and what role NERC may play in the process. Do states really have a meaningful role in the planning process itself? Will planning for the entire interconnection result in Midwestern ratepayers rebuilding infrastructure for the east coast and Gulf Coast states? Is a public policy assessment and modeling criteria that only looks at benefits and neglects to assess costs valid? Is the emphasis on economic planning over reliability appropriate?

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Senior Director - Expansion Planning
Midwest ISO

The Honorable Valerie A. Lemmie
Commissioner, Public Utilities Commission of Ohio, and President of Organization of MISO States (2010)
Mark G. Lauby
Director, Reliability Assessments and Performance Analysis
North American Electric Reliability Corporation (NERC)

2:45 p.m. - 3:00 p.m.
NETWORKING BREAK

3:00 p.m. - 4:45 p.m.
A New World Order? How Gas and Renewable Generation May Soon Stack Up

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Will shifts in underlying economic assumptions soon change the mix in generation? What are the current merchant plant prospects for renewables and natural gas fired plants? Do the underlying shifts in economic factors reinforce or undermine related planning initiatives?

Moderator: The Honorable David C. Boyd
Chairman, Minnesota Public Utilities Commission
Panelists: Dr. Kevin Forbes
Associate Professor of Economics
The Catholic University of America
Gordon B. Pickering
Director, Energy Practice
Navigant Consulting, Inc.
Robert H. Edwards, Jr.
Deputy General Counsel for Energy Policy
U.S. Department of Energy

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Vectren

Silver Associate
Freddi L. Greenberg
RATE RECOVERY ALTERNATIVES FOR NEW POWER PLANT CONSTRUCTION PROJECTS
Rate Recovery Alternatives for New Projects

Martin Bregman
Executive Director, Law
Westar Energy, Inc.
Westar recovery mechanisms

- Transmission Delivery Charge
  - Authorized by Kansas statutes
- Environmental Cost Recover Rider
  - Approved by the Kansas Corporation Commission under its general regulatory authority
- Both initially approved in our 2005 rate case.
- Predetermination is also available for generation and transmission projects.
Transmission Delivery Charge (TDC)

- Authorized by Kansas statute, K.S.A. 66-1237, to encourage new investment in transmission infrastructure.
- Passes through costs of transmission service used to serve Kansas retail customers and billed to us by the Southwest Power Pool.
- Provides timely recovery when coupled with Westar’s annually updated transmission formula rate.
Our FERC transmission formula rate which is based on a projected test year subject to true-up in subsequent years.

- Updated whenever our transmission formula rate changes — once or twice a year.

- By statute, the Commission has 30 business days in which to review and approve changes to the TDC.
Environmental Cost Recovery Rider (ECRR)

- Recovers capital costs (CWIP) of incremental investments in environmental controls installed to meet requirements of the Clean Air Act.
- Updated annually to reflect investment as of year end.
- The ECRR rider is not explicitly authorized by statute but was issued under KCC’s general authority.
ECRR

- We provide six month’s notice of proposed projects to KCC Staff and CURB with description and cost estimate provided.
- Annually we make a tariff filing in March to adjust the ECRR rate effect in June each year.
- In rate cases, the ECRR costs are rolled into base rates.
- The future of the ECRR is in question due to the Commission’s concern about proposed costly retrofits to coal units that went into service in the 1970’s and 1980’s.
**Predetermination**

- K.S.A. 66–1239 allows determination of ratemaking principles to be applied to transmission and generation facilities.
- The Commission has 180 days in which to act.
- Once the Commission rules, it is bound to apply the principles enunciated in all subsequent proceedings related to the facilities.
- We have used this statute before investing in a large peaking unit and before acquiring wind production.
- Now pending before the Commission is an application to install environmental retrofits to a plant we jointly own with KCP&L.
The ECRR and TDC were both approved by the KCC in our 2005 rate case.

Both the ECRR and TDC were appealed to the Kansas Court of Appeals.

Despite the lack of specific authority for the ECRR, the Court ruled that the Commission did have authority to approve it.

The Court overturned the TDC on the ground that the Commission failed to follow the statutory road map for implementation.

Why did Court reject TDC?

- The statute was designed to implement the TDC outside the context of a rate case.
- The statute required that the Commission find that the TDC was equal to the amount of transmission costs that had been embedded in base rates immediately before the TDC became effective.
- Because we had implemented the TDC in a rate case, the Commission could not make such a finding.
Remand and second appeal

- On remand, Westar rolled its transmission revenue requirement into its base rates but proposed to unbundle transmission costs as a “Transmission Service Charge (TSC).”
- The Commission accepted the proposal under its general authority and a second appeal occurred.
- The Court of Appeals upheld the TSC as reasonable and distinguished it from the TDC.
- Among other the things, the TSC could only be changed in a general rate case.
What to do, what to do?

- First, we converted the TSC into a TDC.
- After the appeals were over, the legislature changed the law.
- The TDC statute was changed to work better in the context of a rate case.
- The amendment also addressed issues arising from the fact that FERC generally sets rates subject to refund.
Which is better long-term approach?

- If you can get the statute right, the TDC approach has the advantage of the legislative seal of approval. Unless and until the statute is repealed, the Commission is required to allow recovery under the TDC.
- Because the ECRR is Commission-made, it may be easier for the Commission to change direction.
- If environmental costs go too high, the Commission’s willingness to approve recovery may be affected.
- As plants age, questions concerning the best approach to generation expansion arise.
Construction Work in Progress (CWIP), Credit Metrics Regulation (CMR)…& Maintaining the Option for a New Nuclear Unit in Missouri

Fourteenth Annual Midwest Energy Conference of the Midwest Chapter of the Energy Bar Association

By Warren Wood, PE
Vice President, Regulatory & Legislative Affairs
Ameren Missouri
Electric Rates in Missouri Are Low & Stable

RESIDENTIAL RATES IN THE USA AND PERCENT CHANGE 2000-2010
(EEI SURVEY - SUMMER 2010)

CURRENT 12 MONTH AVERAGE (IN CENTS/KWH)

- Over 15¢
- Between 11¢ and 15¢
- Between 9¢ and 11¢
- Between 8¢ and 9¢
- Below 8¢

Ameren Based on EEI’s Typical Bill Survey, Summer 2010. (Nebraska based on EIA data)
USA Average 11.74¢
Ameren Missouri 7.18¢
39% Below USA Average

USA Average 39%
Ameren Missouri 2%
Electricity Rates, About What They Were 20 Years Ago

• Ameren Missouri’s average electric rates are significantly below the national average.

Source: Edison Electric Institute (EEI)
These plants provide 58% of Missouri’s capacity and 89% of our energy.

We have built little baseload capacity in the last 25 years.
Distribution of the Actual Age at Retirement, 586 Units and 19,407 MW Total Capacity, Source - Velocity Suite

Average Age of Missouri’s Baseload Fleet
Possible Timeline for Environmental Regulatory Requirements for the Utility Industry

- **Ozone (O₃)**
  - Revised Ozone NAAQS
  - CAIR Vacated
  - CAIR Remanded
- **SOₓ/NOₓ**
  - SO₂ Primary NAAQS Revision
  - NO₂ Primary NAAQS
  - CO₂ Regulation (PSD/BACT)
- **CAIR/Transport**
  - Transport Rule proposal issued (CAIR Replacement)
  - Final Transport Rule Expected (CAIR Replacement)
  - Effluent Guidelines proposed rule expected
  - PM Transport Rule
  - 316(b) final rule expected
  - 316(b) Compliance 3-4 yrs after final rule
- **Water**
  - Effluent Guidelines Compliance 3-5 yrs after final rule
- **PM/PM2.5**
  - Begin CAIR Phase I Annual NOₓ Cap
  - Begin CAIR Phase I Annual SO₂ Cap
  - Proposed Rule for CCBs Management
  - 316(b) proposed rule expected
  - Next PM-2.5 NAAQS Revision
  - HAPs MACT Proposal
  - HAPs MACT final rule expected
  - Transport Rule Phase I Reductions
- **Ash**
  - GHG NSPS Proposal
  - Final Rule for CCBs Mgmt
  - Ozone transport Rule
  - Transport Rule Phase II Reductions
  - HAPS MACT Compliance 3 yrs after final rule
- **Hg/HAPS**
  - Begin Compliance Requirements under Final CCB Rule (ground water monitoring, double liners, closure, dry ash conversion)
- **CO₂**
  - Effluent Guidelines
Figure 5: 2018 Reduction in Adjusted Potential Capacity Resources due to the Combined EPA Regulation Scenario

Source:
NERC 2010 Special Reliability Scenario Assessment
Planning for the Future

• Utilities are required to file an Integrated Resource Plan every 3 years
• Ameren Missouri filed a few weeks ago (charts below from report)
• A very important and very resource intensive process with a great deal of discussion with stakeholders with a broad range of interests

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Ameren Missouri Forecast Generation Need

- Generation Surplus
- Generation Need
- Peak Load and Reserve Requirement
- Existing Generation

Levelized Cost of Energy of Generation Options

- Existing Generation
- Coal w/Carbon Capture & Seq.
- Biomass
- Simple Cycle (Nat. Gas)
- Combined Cycle (Nat. Gas)
- Hydro
- Wind
- Nuclear
- Solar

Cents/KWh

[Graph showing generation needs and costs over time, with a focus on nuclear energy options.]
Missouri's utility service providers are facing an unprecedented challenge in their need to build new and/or replace infrastructure:

Power Plants & Environmental Retrofits

It is essential that our state act now to begin to address these challenges in a proactive manner if we hope to keep our electricity reliable and affordable.

All Missourians agree that our continued ability to have highly reliable power, generated in an environmentally responsible manner, which is affordable and competitively priced, is essential to our continued ability to keep, grow and attract the industries and businesses key to our economic vitality.
Major Environmental & Power Plant Projects – Next Steps

- Identify the top infrastructure financing challenges facing utility service providers,
- Identify the range of financing options considered in Missouri and other states,
  - CWIP, Credit Metrics, State Bonding, 3rd Party Financing, etc...
- Engage the stakeholders through a task force, MoPSC docket, or some other meeting vehicle in issues 1 and 2 above (probably with some sort of 3rd party moderator),
- Let the financial and accounting experts from the stakeholder groups carefully look at the options for financing to achieve three primary objectives:
  - Acquire needed financing to make needed investments in infrastructure in a timely manner,
  - Minimize increases on future customer rates, and
  - Maintain/improve credit ratings of utility service providers for reasonable access to, and cost of, capital.
- Third party/moderator report on findings and recommendations for changes to statutes, if any.
Current Activity in Missouri - EARLY SITE PERMIT

- The early site permit (ESP) process enables companies to obtain approval from the NRC for a nuclear power plant site before deciding to build a plant.
- The process resolves site suitability issues before companies commit major funds to the project.
- Companies can “bank” sites approved by the NRC for up to 20 years.
- ESP applications consist of three major components
  - a site safety analysis
  - an environmental report
  - emergency planning information
- An ESP review process can encompass a wide range of reactor technologies which enables companies to select the best design when they proceed with a decision to build.
KEY ADVANTAGES OF AN EARLY SITE PERMIT

• Preserves important option and makes measured progress on a potential nuclear unit.
• Better positions Missouri for federal incentives for nuclear power in the future.
• Allows for reassessment of nuclear technology choices and competitive bidding between possible vendors in the future.
• Allows for ‘lessons learned’ from projects moving ahead in other regions.
• Permits additional study of a number of key issues including customer energy needs, other generation options, energy efficiency programs, financing alternatives and new environmental rules.
• Low cost option (approximately $40 million) that will impact the average residential bill by between eight and sixteen cents per month in the future (likely after 2014).
Missouri Energy Partnership Act

• On November 19, 2010, Governor Jay Nixon announced his support for legislation which would enable the filing of an early site permit, maintain the option to build a nuclear plant in the future and provide important consumer protections.

• On December 6, 2010, Senator Mike Kehoe filed the “Missouri Energy Partnership Act” legislation.

“The Missouri Energy Partnership Act takes the first step toward building more nuclear power production in our state,” said Senator-Elect Kehoe. “By partnering with ratepayers, investor-owned utilities, electric cooperatives and municipal utilities, we can secure Missouri’s energy future and create jobs. It’s the right thing to do now and for our future.”

• On January 6, 2011, Representative Jeannie Riddle introduced HB 124 that would enable the filing of an early site permit at Callaway.
MISSOURI ENERGY PARTNERSHIP ACT – KEY CONSUMER PROTECTIONS

• Short simple legislation that only allows for reimbursement of site permit costs.

• Can only recover cost of the site permit if the U.S. Nuclear Regulatory Commission (NRC) actually grants the permit.

• Dollars spent to obtain the site permit will only be included in rates after the Missouri Public Service Commission (PSC) determines that these expenditures were prudent—likely after 2014.

• Transparency – Regular reporting to the MoPSC on work in progress and expenditures during the site permit development process.

• If the site permit is sold or transferred to another company, ratepayers receive their money back.
FAIR ENERGY RATE ACTION FUND CONDITIONS

• Responsible cap on site permit costs and enhanced monitoring of permit process.
  – *Specific statutory reporting provisions, prudence review of all expenditures, and hard cap of $45 million.*

• A rebate to customers if site permit is obtained but a plant is never built or if the permit is sold at a profit.
  – *If permit is sold, customers will get all their money back, plus interest.*
  – *If permit expires without plant being built, prudence shall be assessed by the PSC. If permit expiration was not prudent management of the asset, customers will get all their money back, plus interest.*

• Increased funding for the Office of Public Counsel (OPC - the residential customer’s consumer advocate).
  – *Governor Nixon’s proposal doubles OPC’s budget - allowing them to fill all open positions and hire expert witnesses in cases before the PSC.*
New Generation Cost Recovery—
A balance of Interests

Midwest Energy Conference
March 15, 2011
Robert Heidorn
Vectren Corporation
Ratepayers Traditionally Fund Used And Useful Plant

- “Imprudent” Investment Absorbed By Shareholders (failed nuclear examples)
- No Recovery For New In-service Plant Until Rate Case—Earnings Reduced (depreciation and financing costs) And No Cash Flow Until Rate Order
- Utilities Confront Regulatory Lag
Are Power Plants Different?

– Magnitude Of Investment – Burden On Utility Financials (ex. interest coverage)
– Multi-year Construction Period-Can You Time The Rate Case?
– Risk Of Change—No Longer Needed?
– Investor View—Want Certainty
Is Need a Slam Dunk?

– Future Demand Uncertainty—Economy, Customer Growth, New Technologies, DSM
– RTO Role—Still Need A Reserve
– New Challenges—Retirements Due To Anticipated GHG Regulation
– Recently Mostly About Peak—Time For New Baseload At Hand
Legislative Answer—Reduced Risk with Regulatory Oversight

– Commission Reviews Need, Supply/Demand Alternatives And Costs
– Commission Approves Estimated Cost
– Commission May Modify Or Revoke Certificate If Need No Longer Exists
Cost Recovery and Limited CWIP

– Absent Fraud Or Gross Mismanagement, For Commission Approved Generation Projects Utility Recovers Project Costs Even If Subsequently Cancelled By Commission (including a return)

– For “Clean Coal Technology” Utility Can Obtain CWIP And Accelerated Depreciation (IC 8-1-2-6.1, 6.6 and 6.7)– Deals With Projects To Address SO$_2$ And NOx
Clean Coal and Energy Projects (IC 8-1-8.8)(2002)

- Legislature Determined Need For New Energy Production, Use Of IN Resources And Economic Development Opportunities
- Statute Covers CCT And New Clean Coal And Renewable Generation
  - Provides For CWIP
  - Incentive Returns On Investment
- Traditional Baseload Coal, Co-Gen and Gas Peakers Not Covered
Conclusion

Statutory Framework Promotes Certain Generation Types and Pre-Approval Of Projects And Costs To Obtain CWIP

Commission Retains Ability To End Approved Projects But Sunk Costs Are Recovered

Frontend Need Showing And Selection Of Resource Is The Primary Regulatory Hurdle
Midwest Energy Bar Association
Annual Meeting
Indianapolis

Prudence In Perspective
Mike Laros
michael.laros@paconsulting.com
812.988.2913

March 15, 2011
Overview:

- **New Generation Projects, Problems, and Cost Overruns** are coming

- **Determining “Prudent and Reasonable” Expenditures** will again be a pressing challenge for Regulators, Owners, other Stakeholders

- **Prudence is a responsibility** that must be addressed proactively by the parties involved

- **This is accomplished by:**
  - Taking advantage of “Lessons Learned” to meet project objectives and establishing a project record
  - Avoiding hindsight
  - Applying appropriate standards
New Power Projects are Coming – How Many and What Type is Uncertain

Assuming long-term gas prices of $5-7/MMBtu, pending environmental regulations would result in less than 5% of U.S. coal-fired capacity retiring...

PA forecasts that under a business-as-usual scenario, approximately 12 GW of coal capacity would retire due to economic pressures created by new environmental regulations:

- The typical retired unit is small (~100 MW) and relatively old (45 years); 55% of capacity is in MISO
- The typical retired unit has an average capacity factor of 60%
- Approximately 90% of the retired capacity are regulated facilities (e.g., utility-, muni- or coop-owned)

Source: PA Consulting Group, Inc. analysis with Ventyx Energy Velocity tools
Under Some Scenarios, the Number, Size, and Cost Could be Very Large

...However, low natural gas prices, combined with pending environmental regulations, could lead to significant retirements among coal-fired generators.

PA forecasts that under this downside scenario\(^1\), approximately 75 GW of coal-fired capacity would be at risk of retirement\(^2\):

- The typical retired unit is ~150 MW and relatively old (~45 years)
- Approximately 50% of the retirements occur in the MISO and PJM regions
- Approximately 75% of the retired capacity are regulated facilities (e.g., utility-, muni- or coop-owned)

Source: PA Consulting Group, Inc. analysis with Ventyx Energy Velocity tools
However, We Do Not Need To Wait for the Future ….

- Some Existing Large Complex Projects Underway or Recently Completed in the Midwest
  - Iatan I – New Pollution Controls
  - Iatan II– New Base Load Coal Plant
  - Edwardsport – IGCC Coal to Gas Plant

- Each of These Projects Has Experienced Significant Cost Increases Over Original Estimates
  - This is fairly typical and can be caused by a variety of factors – some controllable, some outside of managements control
  - None has had any significant “prudence” disallowance (Yet!)
Alternatives for Determining the Facts

- **Retrospective Audit** – “After the Fact” Review of Project Management and Decisions / Actions Effecting Cost and Schedule
  - Can be done after project completion
  - Requires strong controls and experience to provide perspective and avoid hindsight
  - No Opportunity to save money – done “after-the-fact”

- **“Embedded” Project Monitor** – Ongoing oversight of Project Management and Progress
  - Can provide early insight into project progress / potential corrective actions
  - Opportunity to save money by implementing agreed corrective actions
  - Creates a contemporaneous record of decisions / actions / support
  - May become too “embedded” – miss the forest through the trees

- **Prospective Audits** – Periodic contemporaneous reviews of project management activities and cost/schedule reasonableness at key periods over the life of the project
  - All of the above except embed problem
  - Greatest Opportunity to Positively Influence Outcome

- **Pre-Approvals** – Need / Choice of Technology / Early Feasibility Expenditures
Standard of Reasonableness

Major Project Retrospective Prudence Review Standard:

“Reasonable man, looking prospectively, without the benefit of hindsight.”

“Every investment may be assumed to have been made in the exercise of reasonable judgment unless the contrary is shown”

Justice Brandeis
Southwestern Bell Tel v. MOPSC 1923

Perfection not Required
Lessons Learned

- Lots of Prudence Disallowances following the last major generation build-up
  - DOE estimated 16% of base rates disallowed on 12 nuclear projects it studied

- Question - Was this the result of “Regulatory Opportunism,” “Bad Luck,” or “Bad Management”??
Had

Regulators gone WILD?
Conclusion:

“The empirical results do not support the proposition that there was a violation of the “regulatory contract” as a result of the cost disallowances of the 1980s……. Most utilities apparently saw the disallowances as indicative of bad management by the affected firms, and saw no reason to change their own investment practices.”

Lyons & Mayo – Rand Journal of Economics, 2005
Regulatory Opportunism and Investment Behavior: Evidence from the U.S. Electric Utility Industry
What Went Wrong????

- Poorly structured contracts
- Failure to recognize internal and external resource limitations
- Inadequate owner oversight
- Lack of information to make informed decisions
- Over reliance on contracts and litigation to remedy problems
- Inadequate financial planning
- Poor and untimely resolution of engineering problems
- Failure to take timely corrective action
- Owner not prepared to accept operational responsibility....

- Unclear lines of responsibility between the owner & contractor
- Inadequate project information requirements
- Inadequate Board / Senior management attention
- Owner failure to mitigate potential problems
- Failure to change with conditions or react to problems
- Over reliance on contracts and litigation as a remedy to solvable problems

The Result:
Over three years of delay and a doubling of costs – at least half of which was avoidable in spite of serious project complexities and contractor failures not envisioned at the onslaught of the project
What Can (Should) You Do About It???

✓ **Plan** - Consider appropriate range of project contractual options given the legal & regulatory environment and the realities of the project – evaluate how projects differ from those done before – organize resources and develop policies and procedures necessary for defining responsibilities and accountabilities.

✓ **Prioritize** - Identify risk exposure areas and develop contingency plans - Keep your eye on the ball and maintain flexibility to adopt to changing project conditions.

✓ **Manage** - Develop a framework for effective project management resources, tools and reporting requirements needed for project management and control – including timely corrective action when required.

✓ **Collaborate** - Get your regulators & key stakeholders involved - where possible, obtain pre-approval or certification from regulators regarding the project.

✓ **Document** - Formalize prospective independent project assurance including documentation of key activities and decisions.
In Summary…

- New Generation Projects, Problems, and Cost Overruns are coming

- Determining “Prudent and Reasonable” Expenditures will again be a pressing challenge for Regulators (& Owners)

- Prudence is a responsibility that must be addressed proactively by the parties involved

- This is accomplished by:
  - Taking advantage of “Lessons Learned”
  - Determining the facts and applying appropriate standards
  - Planning for prudence case
About PA Consulting Group

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HOT TOPICS – GENERAL COUNSEL PERSPECTIVES
ON REGIONAL TRANSMISSION ORGANIZATION ISSUES
Emerging Energy Technologies: Integrating Wind into the Nation’s Transmission Grid
Stephen G. Kozey & Corrie Bilke*

Introduction

In 2004, then-Chairman of the Federal Energy Regulatory Commission (“FERC” or “Commission”), Pat Wood III, provided the following assessment of wind energy as a viable alternative to more traditional energy resources such as coal or natural gas:

[Get]ing the [wind] plants built, getting the generation built is a very big step, but it’s not the ultimate step. The ultimate step is getting that renewable power to the customer . . . Barriers to entry for the wind energy have been and continue to be significant . . . Because it’s all about nondiscrimination . . . It’s giving a new technology which has a popular appeal, which has good environmental attributes, giving that technology a fair seat at the table with coal, nuclear, hydro, and gas . . . I think the biggest barrier today that’s preventing wide access to wind resources reaching customers is [the lack of] a robust transmission grid.1

Chairman Wood’s sentiment was recently echoed by current FERC Chairman Jon Wellinghoff: “[W]e need a National policy commitment to develop the extra-high voltage (“EHV”) transmission infrastructure to bring renewable energy from remote areas where it is produced most efficiently into our large metropolitan areas where most of this Nation’s power is consumed.”2 As suggested by both former Chairman Wood and current Chairman

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The Midwest ISO ensures reliable operation of, and equal access to, 57,453 miles of interconnected, high-voltage power lines in 13 U.S. states and the Canadian province of Manitoba. The Midwest ISO manages one of the world’s largest energy and operating reserves markets. The Midwest ISO was approved as the nation’s first regional transmission organization (“RTO”) in 2001. The non-profit 501(c)(4) organization is governed by an independent Board of Directors, and is headquartered in Carmel, Indiana with operations centers in Carmel and St. Paul, Minnesota. Membership in the Midwest ISO is voluntary. For more information, visit www.midwestiso.org.

Please note that the opinions expressed in this article belong solely to the authors. Nothing contained herein shall be construed as the position of the Midwest ISO.


Wellinghoff, the potential benefits of renewable energy have no bearing unless that energy can be delivered to the end-user in a safe, reliable, and cost-effective manner. Today, utilities and regulators continue to face those challenges presented when integrating alternative energy resources, such as wind and solar, into the transmission grid; whether that requires building new transmission facilities, or making improvements to existing facilities to accommodate these new resources.

The purpose of this article is to briefly discuss a few of the questions presented by integrating renewable resources into the nation’s transmission grid, including:

- What is the significance of transmission planning and development?
  - What is transmission?
  - Is constructing transmission facilities a right, an obligation, or an opportunity?
  - What is the ultimate goal of transmission planning?
- What kind of challenges does wind energy present to transmission operators and planners?
- Alternatively, what kind of challenges does transmission siting present?
  - Who has jurisdiction over transmission siting?
  - What are some of the issues associated with off-shore siting?
- What are some of the challenges associated with cross border transmission projects?

I. What is the significance of transmission planning and development?

As noted above, energy resources, renewable or otherwise, have little significance if the power they produce cannot be transported to load in a safe, reliable, and cost-effective manner. To meet this objective, transmission planners engage in extensive studies that span periods of months and years in order to develop a transmission network capable of meeting industry demands, regulatory requirements, and political agendas. Before a meaningful discussion of integrating renewable resources into the nation’s transmission grid can begin, it is important to consider first those issues relevant to transmission planning and development, including: (1) what is transmission; (2) is constructing transmission facilities a right, an obligation, or an opportunity; and (3) what is the ultimate goal(s) of transmission planning?

a. What is transmission?

“Transmission, sometimes referred to as ‘bulk transmission’ or ‘wholesale transmission,’ means the transmission of wholesale electricity from generators to the point in the electric system where delivery to customers begins.”\(^3\) The delivery of power to retail customers is

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referred to as “distribution.” 4 “[T]ransmission systems consist of poles and wires, substations, transformers, and other equipment used to move power from generators to the distribution system.” 5

Under the Federal Power Act (“FPA”), 6 FERC “has jurisdiction over the provision of unbundled transmission service in interstate commerce – including all transmission service except that provided in Alaska, Hawaii, and most of Texas.” 7 With the issuance of Order No. 888, 8 FERC requires owners of transmission facilities to make those facilities available to all generators on a non-discriminatory basis at a rate regulated by FERC. 9 Order No. 888 was a landmark case, as it “required transmission-owning entities to file tariffs with FERC making transmission service available to other utilities, independent generators, municipal and rural cooperative systems, and power marketers, under the detailed terms and conditions set forth in those tariffs.” 10 In turn, “[t]his new access to the transmission grid allowed for the development of wholesale power markets in which all those entities could participate.” 11

The FPA further authorizes FERC “to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy.” 12 Under the FPA, it is “the duty of the Commission to promote and encourage such interconnection and coordination within each such district and between such districts.” 13 The United States transmission system is made up of three major, multi-state, electrically interconnected grids: (1) the Eastern Interconnect, which includes the eastern and central states; (2) the Western Interconnect, which spans the Rocky Mountain and southwestern states; and (3) the Electric Reliability Council of Texas interconnect, which includes most of the state of Texas. 14 Within each of these interconnects, “the transmission

4 Id.

5 Id. at 11.


7 Steinhurst, supra, at 11.


9 Steinhurst, supra, at 12.

10 Id. at 12.

11 Id.


13 Id.

14 Steinhurst, supra, at 12.
system is operated by local utilities and [regional transmission operators] (e.g., Midwest ISO in the Eastern Interconnect).

b. **Is constructing transmission a right, an obligation, or an opportunity?**

While there is no intrinsic right, nor explicit obligation, on the part of utilities to build transmission, utilities do have an obligation to provide reliable service at a reasonable cost. In order to accomplish this, a robust transmission system is essential. By way of FERC’s jurisdictional authority over transmission rates, and the state’s authority over transmission siting, the government has established an elaborate set of rules to regulate who can build transmission, where transmission can be built, and under what conditions transmission may be operated.

As the availability of and public interest in renewable energy resources continues to grow, transmission is becoming more appealing as a profitable business enterprise opportunity. Nonincumbant transmission developers look to become more involved in the transmission planning process; likewise, FERC is working to address any potential opportunities for undue discrimination and preferential treatment against these entities within existing regional transmission planning processes.

c. **What is the ultimate goal(s) of transmission planning?**

“Among other purposes, transmission planning is the means by which the transmission needs of a given area and the facilities that are best suited to meet those needs are identified.” Historically, a utility’s transmission planning efforts had two major objectives: (1) link generation owned by the utility to that same utility’s load centers; and (2) interconnect with neighbors to share reserve obligations. In order to accomplish these objectives, transmission planners sought to develop transmission in the least expensive way available while maintaining system reliability. Today, however, the old paradigm of transmission planning seems to no longer apply as transmission planning is done on a much broader scale, and planners work to address a number of new issues related to transmission development never before considered, including how to bring renewable energy sources to load. Developing transmission at the least expensive cost is no longer enough; today’s transmission planners face a number of sometimes competing constraints or goals, including efforts to: (1) minimize

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15 Id. at 12.
16 See supra notes 6-10 and accompanying text.
17 See infra notes 52-53 and accompanying text.
19 Transmission Planning NOPR at P 44.
investment risk (seek shorter payback horizon); (2) maximize carbon reduction (replace coal production); (3) maximize local economic development (install wind directly within Renewable Portfolio Standard state); and (4) maximize economic value (seek lowest cost to customer).  

FERC has established certain transmission planning principles with the issuance of Order No. 890 and its more recent Notice of Proposed Rulemaking on Transmission Planning and Cost Allocation. As discussed below, the Midwest ISO’s transmission planning efforts seek to coincide with those principles established by the Commission to ensure that services are provided on a basis that is just, reasonable, and not unduly discriminatory or preferential.

i. Order No. 890 and 2010 Transmission Planning NOPR

In 2007, FERC issued its Final Rule in Docket Nos. RM05-17-000 and RM05-25-000 (“Order No. 890”) in order to “ensure that transmission services are provided on a basis that is just, reasonable, and not unduly discriminatory or preferential.” Among other things, Order No. 890 “exempts intermittent energy power generators from excessive charges due to scheduling deviations, effectively ending the discriminatory consequences that once plagued renewable energy providers.” Order No. 890 is an example of FERC’s continuing efforts to identify and remedy discriminatory policies “and to level the playing field for the less predictable forms of the renewable energy generators.”

Order No. 890 further requires that transmission providers participate in a coordinated, open and transparent planning process on both a local and regional level. Order No. 890 further requires that each transmission provider’s process meet FERC’s nine planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; (7) regional coordination; (8) economic planning studies; and (9) cost allocation.

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21 See infra notes 23-28 and accompanying text.
22 See infra notes 29-32 and accompanying text.
24 Id.
26 Id. at 181.
27 Order No. 890 at P 435.
28 Id. at P 444-561.
On June 17, 2010, FERC issued its Notice of Proposed Rulemaking on Transmission Planning and Cost Allocation in Docket No. RM10-23-000. In the Transmission Planning NOPR, the Commission proposed to amend the transmission planning and cost allocation requirements of Order No. 890 to account for changes in the industry since its issuance in 2007. With regard to transmission planning, reforms proposed in the NOPR would, among other things, provide that:

1. Local and regional transmission planning processes account for transmission needs driven by public policy requirements established by state or federal laws or regulations;
2. Coordination between neighboring transmission planning regions is improved with respect to facilities that are proposed to be located in both regions, as well as interregional facilities that could address transmission needs more efficiently than separate intraregional facilities; and
3. A right of first refusal that is created by a document subject to the Commission’s jurisdiction and that provides an incumbent utility with an undue advantage over nonincumbent transmission project developers is removed from that document.

With regard to transmission cost allocation, the Transmission Planning NOPR proposes “to require public utility transmission providers to establish a closer link between cost allocation and regional transmission planning processes in which the beneficiaries of new transmission facilities are identified, as well as to establish principles that cost allocation methods must satisfy.”

**ii. Transmission Planning at the Midwest ISO**

The Midwest ISO follows the Order No. 890 planning principles for a regional planning process that is open, transparent, coordinated, and equitable. The Midwest ISO transmission planning team recognizes that it faces a number of challenges in its efforts to develop and continually improve a comprehensive planning approach that meets the ever-evolving reliability and economic expansion planning needs of its customers. Key issues confronting the

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29 See Transmission Planning NOPR, supra note 18. The Midwest ISO submitted comments in response to the NOPR on September 29, 2010. As of the date of this writing, FERC has yet to issue a Final Rule in this docket.

30 Id. at P 32-43 (discussing the need for reform).

31 Id. at P 4.

32 Id. at P 5.

33 For additional information on the Midwest ISO’s planning process, see the “Planning” tab on the Midwest ISO website (http://www.midwestiso.org/Planning/Pages/Planning.aspx).
Midwest ISO “include introduction and implementation of new renewable energy policies, reduction of grid congestion, and incorporation of new generation and demand response programs – all while still meeting load growth requirements.” To address these multi-faceted challenges, the Midwest ISO coordinates short- and long-term planning using advanced modeling techniques and thorough research in order to ensure reliable and efficient electricity transmission in its footprint and beyond. Specifically, the Midwest ISO applies the following guiding principles in its planning efforts:

- **Guiding Principle 1**: Make the benefits of a competitive energy market available to all customers by providing access to the lowest possible delivered electric energy costs.
- **Guiding Principle 2**: Provide a transmission infrastructure that safeguards local and regional reliability and supports interconnection-wide reliability.
- **Guiding Principle 3**: Support state and federal renewable energy objectives by planning for access to all such resources such as wind, biomass, demand-side management.
- **Guiding Principle 4**: Provide an appropriate cost allocation mechanism.
- **Guiding Principle 5**: Develop a transmission system scenario model and make it available to state and federal energy policy makers to provide context and inform the choices they face.

The Midwest ISO is also conducting various studies to review the impact of wind in its markets, including the Regional Generation Outlet Study (“RGOS”) and the Midwest Transmission Expansion Plan (“MTEP”). “[RGOS], which seeks to address the renewable portfolio mandates in effect in the Midwest ISO [region] through 2025, is an example of a transmission study that takes a regional view to develop longer-term solutions that can begin to be implemented in the present.” In order to assist states with identifying and developing regionally coordinated transmission projects, RGOS study objectives include:

1. Analyzing and planning for each state’s renewable portfolio standards.
2. Setting goals for meeting load-serving entities’ renewable portfolio standards.
3. Balancing distribution of wind zones to consider local desires, optimal wind conditions and distances from load.
4. Providing consumers with energy solutions at the least possible cost.

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35 See id. at 41.

36 Id.
(5) Identifying transmission expansion starter projects.\textsuperscript{37}

The Midwest ISO Transmission Expansion Planning cycles last approximately 18 months, and findings are reported in an annual report. The annual MTEP identifies solutions to meet transmission needs and to create value opportunities in the future by implementing a comprehensive planning approach.\textsuperscript{38} The primary purpose of MTEP is to identify transmission projects that:

(1) Ensure the reliability of the transmission system.
(2) Provide economic benefits such as increased market efficiency.
(3) Facilitate public policy objectives such as integrating renewable energy.
(4) Address other issues or goals identified through the stakeholder process.\textsuperscript{39}

As discussed in more detail below, the Midwest ISO has recently made tremendous strides with its transmission planning process with the creation of Multi Value Projects.\textsuperscript{40} According to a public statement made by Commissioner Wellinghoff:

The Midwest ISO’s proposal is the next step in the evolution of its transmission planning and cost allocation process. The creation of a new category of projects, “Multi Value Projects,” will enable the Midwest ISO to identify those projects which create regional benefits. As evaluation of these projects will occur in the MTEP process, Midwest ISO’s existing open and transparent transmission planning process, stakeholders will have the opportunity to analyze the proposed projects in the context of a regional planning process that takes into account the diverse needs of the Midwest ISO footprint.\textsuperscript{41}

II. What kind of challenges does wind energy present to transmission operators and planners?

Wind energy presents a number of challenges for transmission operators and planners alike, many of which the industry has never faced until now due to the unique nature of wind as an energy resource. First, from an operational standpoint, unlike more traditional fuel types such as coal or gas, wind cannot typically be dispatched and it is difficult to reduce its output.\textsuperscript{42}

\textsuperscript{37} See \url{http://www.midwestiso.org/Planning/Pages/RegionalGenerationOutletStudy.aspx}.

\textsuperscript{38} See MTEP 2010 at 1.

\textsuperscript{39} Id.

\textsuperscript{40} See infra notes 81-85 and accompanying text.


\textsuperscript{42} See the information provided on Midwest ISO’s Wind Integration Initiative website, available at
By its very nature, wind energy is highly variable, as wind speeds at a specific geographic location fluctuate as a result of changing weather patterns. Also, in general, wind output is negatively correlated to system load, meaning strong wind is present when demand is low (e.g., mid-night) and absent when demand is high (e.g., mid-day). The intermittent nature provides no guarantee of wind capacity availability on peak.

The presence of wind turbines has also prompted debate among environmentalists and local landowners. For example, some have claimed that “wind energy can result in increased injury and mortality among birds that collide with turbine blades, and aesthetic concerns may

https://thegrid.midwestiso.org/SiteDirectory/WindII/Pages/FrequentlyAskedQuestions.aspx. (hereinafter “Wind Integration Initiative Website”). On November 1, 2010, in Docket No. ER11-1991-000, the Midwest ISO filed proposed revisions to its Open Access Transmission, Energy and Operating Reserve Markets Tariff (“Tariff”) to include a new resource designation, Dispatchable Intermittent Resource (“DIR”), in order to fully integrate Intermittent Resources, particularly wind resources, into the Midwest ISO market. (“DIR Proposal”) In its filing, the Midwest ISO noted that wind resources have been traditionally classified as Intermittent Resources because their fuel source, wind, itself cannot be controlled. The Midwest ISO further explained:

Notwithstanding such lack of control over the fuel source, however, the amount of wind energy that is used by such resources can, in many cases now be controlled. Accordingly, many wind resources are capable of being dispatched in a manner to reduce output by using such techniques as pitch control (i.e., controlling the speed of a wind turbine by varying the orientation, or pitch, of the blades) or by curtailing individual wind turbines on a large wind farm. As a result, these wind resources may be dispatchable in the downward direction (output reduction) while at the same time being fuel-limited in the upward direction (output increase). Utilizing the potential capability of wind resources to be dispatchable in the downward direction would allow for market-based solutions to many potential congestion and minimum generation issues. Implementation of the proposed Tariff changes will benefit participants in the Midwest ISO markets by improving operational efficiency, market efficiency, and market transparency, and by providing a level playing field among Market Participants. Wind generators, and other generators that qualify as DIRs, will benefit specifically from full participation in the market, eligibility for make-whole payments, and transparent dispatch.

DIR Proposal, page 2-3 of the transmittal letter (internal citations omitted).

As of January 11, 2011, FERC had yet to issue an Order in this docket.

Wind Integration Initiative Website, supra note 12.

Id. See also Robert J. Michaels, National Renewable Portfolio Standard: Smart Policy or Misguided Gesture, 29 Energy L. J. 79, 100 (2008)(“Wind’s usefulness to a grid operator is further lowered by the general inverse association between peak loads and wind velocities. . . [For example, at] the five highest load hours of 2006, wind units in California produced an average of 12.2% of their normal capabilities.”).

See “Midwest ISO Integration of Wind” presentation available at https://thegrid.midwestiso.org/SiteDirectory/WindII/Pages/GuidesReferences.aspx.
result in discontent among homeowners suddenly faced with fields of metal towers in their neighborhoods.”

Furthermore, some of the most significant obstacles presented by wind energy are caused by the “inconvenient” geographic locations where these resources are most abundant. Arguably, the biggest challenge of utilizing wind to meet energy demands “is not the shortage of wind turbines . . . but, instead, a deficiency of transmission lines to move the produced energy long distances from a typically remote inception point over to customers in the suburbs or big cities.” Financial, political and regulatory hurdles in building transmission lines have delayed, or in some cases, altogether terminated the completion of such projects necessary to transport this energy from the generator to the areas with the highest demand.

Finally, the goals established by State Renewable Portfolio Standards amplify the need to establish a strong, interconnected transmission network to connect these wind-heavy areas with the states that have vowed to make renewable resources a major part of their energy supply portfolios. While enhancements to the transmission grid represent not only an opportunity to enhance the range of energy resources available to meet the nation’s growing energy demands, it is also an obligation that utilities and regulators must work together to address if states are to meet the renewable portfolio standards that they have established for themselves.

Due to these unique challenges, transmission planners must consider a number of factors in order to optimize potential wind resources. For example, when analyzing potential wind sites, Midwest ISO transmission planners consider the following key factors: (1) generation capital cost (The capacity factor of the selected wind site drives the level of generation to meet the goal; some areas have better wind resources than others); (2) cost of infrastructure to deliver generation (Generation placed in a higher capacity factor location farther from load will require increased transmission cost when compared to generation placed closer to load); and operating costs (Primarily reflected through ancillary services costs and market wide charges, operating costs are ideally minimized through the selection of sites which have an inverse correlation in availability to attenuate problems with ramp caused by sudden shifts in resource availability).


47 Id. at 177.

48 Id. at 177-78 (noting that due to the various political, financial, and regulatory barriers, “it usually takes five to seven years on average to build an electricity delivery system while it may only take about one year to build a wind farm.”).

49 See “Midwest ISO Integration of Wind” presentation available at https://thegrid.midwestiso.org/SiteDirectory/WindII/Pages/GuidesReferences.aspx.
IIII. What kind of challenges does transmission siting present?

As discussed in detail above, “[t]ransmission planning is a critical component of the provision of transmission service in interstate commerce.”\textsuperscript{50} Transmission planning is a separate and distinct issue from transmission siting. Whereas “transmission planning is the means by which the transmission needs of a given area and the facilities that are best suited to meet those needs are identified,”\textsuperscript{51} transmission siting is the means by which the actual route of the physical line is sited in accordance with applicable state or federal law. Transmission siting implicates a number of new challenges separate from those involved with transmission planning, including most notably, those related to jurisdiction.

\textbf{a. Who has jurisdiction over transmission siting?}

Jurisdiction over transmission siting traditionally rests within the individual state’s purview, “in which the siting determination is made on a centralized basis by a designated state agency.”\textsuperscript{52} “State siting agencies’ centralized proceedings enable the public to participate in utility planning and siting of facilities in exchange for a single forum applying a single set of statewide policies for making siting decisions . . . and combine state powers into a single agency.”\textsuperscript{53}

In the 2005 Energy Policy Act (“EPAct of 2005”), however, Congress expanded the authority of the federal government in transmission siting:

In the 2005 Energy Policy Act, Congress amended the Federal Power Act, for the first time delegating authority to [the] Department of Energy (“DOE”) to designate National Interest Energy Transmission Corridors (“NIETCs”) and to FERC to exercise some ‘backstop’ permitting authority over states within the NIETCs. According to these amendments, DOE ‘may designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor.’\textsuperscript{54}

EPAct of 2005 requires the DOE to perform studies of electric transmission congestion on the national power grid every three years.\textsuperscript{55} Based on these studies, the DOE identifies those

\textsuperscript{50} Transmission Planning NOPR at 44.

\textsuperscript{51} Id.


\textsuperscript{53} Id. at 708.

\textsuperscript{54} Id. at 741 (internal citations omitted).

\textsuperscript{55} Kenneth C. Baldwin, Energy Facility Siting, in Capturing the Power of Electric Restructuring 133, 158 (Joseph Lee Miranda ed. 2009).
“geographic regions suffering from overburdened transmission facilities that suffer from decreased consumer satisfaction and electricity supply”, which are formally designated as NIETCs.56 The federal “backstop” siting authority of FERC, as established by EPAct of 2005, “trumps state utility and siting commissions in the siting of transmission lines along NIETCs” in accordance with the various conditions enumerated in the statute.57

The impact of federal involvement in state transmission siting decisions is yet to be determined. Some industry commentators suggest that “[t]he mere threat of federal preemption, such as the federal authority delegated by Congress in EPAct of 2005] may influence states’ behavior by inducing them to approve more projects or act more quickly on [siting] applications.”58 However, a 2009 decision stemming from the U.S Court of Appeals for the Fourth Circuit has placed this observation in doubt. In Piedmont Environmental Council v. FERC,59 petitioners requested that the court review FERC’s determination that its backstop authority can apply when the state denies a permit application. The court determined that FERC’s backstop permitting jurisdiction when a state commission has withheld approval [of a permit application] for more than 1 year does not apply when the state denies a permit

56  Id. In determining whether or not an area is a NIETC, the DOE must consider the following factors:

1. Whether the economic vitality and development of the area or the end markets served in the area may be constrained by lack of reasonably priced electricity.
2. Whether economic growth or the end markets in the area may be jeopardized by the limited sources of energy.
3. Whether a diversification of supply is warranted.
4. Whether the nation’s energy independence would be served by the designation.
5. Whether the designation would be in the interest of national energy policy.
6. Whether the designation would enhance national defense and homeland security.

57  Id. at 158-59.

58  Swanstrom & Jolivet, supra, at 457.

application.60 “As a practical matter, this gives the states the ability to avoid federal preemption entirely by simply denying an application outright (rather than taking too long to act or conditioning an approval excessively).” 61 As illustrated by Piedmont Environmental Council, the jurisdictional boundaries of transmission siting decisions continue to evolve.

b. What are some of the issues associated with off-shore siting?

Wind farm developers have looked beyond the confines of the continental United States for the ideal location of their next project. Projects placing wind turbines off the coast have presented a new set of challenges to the integration of wind energy, most notably, whether the coastal state at issue or the federal government has jurisdiction to determine whether or not these facilities are constructed. According to the Submerged Lands Act, 62 “a coastal state’s territory, including title to the seabed and underlying minerals, extends three miles seaward.” 63 “For wind farm developers, this means that either the generation site itself or transmission lines to deliver the electricity to the mainland will require the cooperation of the state siting authority, be it local or state-run.” 64 Alternatively, under the Outer Continental Shelf Lands Act, 65 the federal government has jurisdiction and the right of development beyond a coast state’s 3-mile territory. 66

Similar to land-based wind farms, off-shore wind farms also raise concerns among environmentalists and local landowners. “Property owners and residents fear the detrimental impact visible wind turbines may have, not only on their use and enjoyment of their oceanfront property, but also on its market value.” 67 For environmentalists, “[t]he concern is that the

60 Id. at 310. In April, FERC sought rehearing of the court’s decision; the petition was inevitably denied. See Piedmont Envtl. Council v. FERC, No. 07-1651 (4th Cir. April 20, 2009).

61 Swanstrom & Jolivert, supra, at 449.


64 Baldwin, supra, at 149 (providing the Cape Wind project in Nantucket Sound off the coast of Massachusetts as an example of when state exercised control of wind project).


66 Smith, supra, at 285 (noting that the Outer Continental Shelf Lands Act “gives the federal government exclusive jurisdiction over the subsoil, seabed, and structures to the furthest extent permitted by international law.”).

67 Baldwin, supra, at 150.
siting and existence of underwater transmission lines upset ocean life not only through physical disturbance, but also with the continued existence of noise and electromagnetic fields.”

IV. What are some of the challenges associated with cross border transmission projects?

Cross border transmission projects also present a number of challenges for transmission planners, including issues associated with lines that cross from one RTO region to another, and more commonly, issues related to projects that cross states’ geographical borders. States will oftentimes coordinate with one another to resolve potential power supply and transmission planning issues. The Organization of MISO States (“OMS”), the Midwest Governors’ Association (“MGA”), and the Upper Midwest Transmission Development Initiative (“UMTDI”) are examples of multi-state collaboration efforts in the Midwest ISO region. The Midwest ISO regularly coordinates with these groups in its transmission planning efforts and initiatives.

In September 2010, UMTDI issued an executive report in which it identified the following accomplishments it had achieved in the preceding two years:

1. Serv[ed] as a catalyst for current transmission policy development, including regional transmission planning techniques and cost allocation approaches.

68 Id.

69 See Midwest Independent Transmission System Operator, Inc., 133 FERC ¶ 61,275 (2010)(accepting and suspending proposed tariff sheets to establish a methodology to allocate and recover the costs of ITC Phase Angle Regulating Transformers (PAR) on the Michigan-Ontario border among Midwest ISO, New York Independent Transmission System Operator (NYISO), and PJM Interconnection, LLC (PJM)).

70 Swanstrom & Jolivert, supra, at 442.

71 “The purpose of the OMS is to coordinate regulatory oversight among the states; making recommendations to the Midwest Independent [Transmission] System Operator (MISO), the MISO Board of Directors, the FERC, other relevant government entities, and state commissions as appropriate; and intervening in proceedings before the FERC and in related judicial proceedings to express the positions of the OMS.” See OMS Mission Statement, available at http://www.misostates.org/MISSION.htm.

72 “[MGA] is a nonprofit, nonpartisan organization that brings together the governors of Midwestern states to work cooperatively on public policy issues of significance to the region.” See http://www.midwesterngovernors.org/about.htm. Members of MGA include the governors of the following states: Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Ohio, South Dakota and Wisconsin.

73 “In 2008, the governors of Iowa, Minnesota, North Dakota and Wisconsin formed [UMTDI]. The goal of this effort was to identify and resolve regional transmission planning and cost allocation issues associated with the delivery of renewable energy from wind rich areas within the five-state footprint to the region’s customers.” See UMTDI Executive Committee Final Report, dated September 29, 2010, available at http://www.misostates.org/UMTDISummaryReportFinal.pdf.
2. Identified the existing legal structures and impediments to further regional cooperation on transmission siting.
3. Developed a set of cost allocation principles that can serve as a foundation for ongoing cost allocation discussions in the region and the country.
4. Designated regional renewable energy zones that have been adopted by the Midwest ISO as optimal areas for further wind development as part of broader transmission planning efforts.
5. [I]dentified six renewable transmission corridors that could be considered as primary paths for the first stage of future transmission analysis and development in the region in an effort to advance energy, economic, and environmental progress in the five states.74

In December 2010, MGA issued a news release in which it applauded the Midwest ISO for the release of its Regional Generator Outlet Study (“RGOS”).75 According to the news release, the RGOS “will also assist the MGA in meeting its regional goal of producing 30 percent electricity from renewable resources by 2030, which governors agreed to in 2007 through their Energy Security and Climate Stewardship Platform for the Midwest.”76 A representative of MGA also noted: “The MGA looks forward to working with the Midwest ISO on their next steps to develop projects and initiatives that meet our region’s long-term transmission needs and create jobs in the new energy economy.”77

While this inter-state cooperation does occur, cost allocation disputes still have a tendency to arise when cross-border transmission projects are considered.78 “Politically, it is difficult for state officials to justify a high-cost transmission project when their ratepayers are asked to foot the bill for the project, but the project arguably benefits [those in other states].”79

FERC has emphasized that cost allocation reform is one of the most difficult issues facing transmission service providers, regional transmission organizations and independent system operators. In a recent order, the Commission explained:

74 Id. at p. 3-4.
76 Id.
77 Id.
78 Swanstrom & Jolivert, supra, at 442. See also Sustainable Development in the Courts: Conference Proceedings: 21st Century Infrastructure: Opportunities and Hurdles for Renewable Energy Development, 10 Sustainable Dev. L. & Pol’y 69 (2009)(“One of the primary issues with transmission development is determining who is going to pay and how.”).
79 Swanstrom & Jolivert, supra, at 443.
Cost allocation reform is one of the most difficult issues facing transmission service providers and regional transmission organizations (RTO) and independent system operators (ISO), including Midwest ISO. This is especially true given the changing circumstances affecting the transmission grid, including particularly, the need to upgrade existing transmission infrastructure and build new transmission facilities to satisfy the expanding demands of the transmission system. Efforts to integrate new resources, including significant amounts of location-constrained generation, into existing transmission systems and to address renewable portfolio standards and other regulatory policies challenge existing transmission planning and cost allocation protocols. The expansion of energy markets across the Midwest ISO region, the need to modernize aging infrastructure, and the necessity of maintaining reliable service are also testing existing transmission planning and cost allocation mechanisms.

On July 15, 2010, the Midwest ISO and Midwest ISO Transmission Owners filed proposed revisions to the Midwest ISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (“Tariff”) in order to establish a new category of transmission projects designated as Multi Value Projects (“MVP”). The MVP designation is for projects that are determined to enable the reliable and economic delivery of energy in support of documented energy policy mandates or laws that address, through the development of a robust transmission system, multiple reliability and/or economic issues affecting multiple transmission zones. In recognizing the regional orientation of such projects, the Midwest ISO proposed that the costs of the MVPs be allocated to all load in, and exports from, Midwest ISO on a postage stamp basis.

On December 16, 2010, FERC conditionally accepted the Midwest ISO’s cost allocation proposal, finding “that the MVP methodology will identify projects that provide regional benefits and allocate the costs of those projects accordingly.” FERC further explained: “The proposed MVP methodology is an important step in facilitating investment in new transmission facilities to integrate large amounts of location-constrained resources, including renewable generation resources, to further support documented energy policy mandates or laws, reduce congestion, and accommodate new or growing loads.”

81 See id. at P 1 (summarizing the Midwest ISO’s proposal).
82 Id.
83 Id.
84 Id. at P 3.
85 Id. In support of the Order, Commissioner Wellinghoff commented: “The Midwest ISO’s proposal was the
This approval followed FERC action on a “highway/byway” cost sharing arrangement by Southwest Power Pool, Inc. (“SPP”) and rejection in the 7th Circuit of a bright-line test in the PJM region. According to the U.S. Court of Appeals for the 7th Circuit:

FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members. “[A]ll approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them. Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.’ To the extent that a utility benefits from the costs of new facilities, it may be said to have ‘caused’ a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed.

Conclusion

Former FERC Chairman Pat Wood III suggested that wind energy would not receive a fair seat at the table with more traditional energy resources unless a robust transmission grid was established to connect available wind resources to areas with the highest demand. The full potential of renewable energy, including wind, cannot be fully recognized unless that energy can be delivered to the end-user in a safe, reliable, and cost-effective manner. While wind energy presents a number of unique challenges from a transmission planning perspective, regulators and utilities must collaborate to find viable solutions if states are to meet the renewable portfolio standards to which they have committed.

result of a lengthy stakeholder process that included participation and hard work by all stakeholders, including state commissions. I’d like to commend all of the Midwest ISO stakeholders for their hard work in forging a regional solution to this difficult issue.” Wellinghoff statement, supra note 41.

86 Southwest Power Pool, 131 FERC ¶ 61,252 (2010)(“[W]e find that SPP’s proposed Highway/Byway Methodology will foster improvements in SPP’s transmission system by consolidating and simplifying the cost allocation process and by providing greater certainty for cost recovery. The proposed Highway/Byway Methodology is an important step in facilitating investment in new transmission facilities to integrate the eastern and western portions of the SPP grid, reduce congestion, efficiently integrate new resources, and accommodate new or growing loads.”).

87 Illinois Commerce Commission v. FERC, 576 F.3d 470 (7th Cir. 2009)(reviewing FERC approval of PJM’s proposed cost allocation methodology, in which all new facilities with capacities of less than 500 kV would be financed by contributions from electrical utilities in the PJM region calculated on the basis of the benefits that each utility receives from those facilities; and all new facilities with capacities at or above 500 kV would be financed by all utilities in PJM’s region on a pro rata basis.).

88 Id. at 476 (internal citations omitted).
As discussed above, the old paradigm of transmission planning seems to no longer apply. Developing transmission at the least expensive cost is no longer enough. Today, transmission planning is done on a much broader scale, and planners work to address a number of new issues related to transmission development never before considered with a new goal in mind: maximize economic value and reliably deliver energy at the lowest cost to the customer.

As illustrated by its recent cost allocation proposal, and the comprehensive stakeholder process that preceded its filing at FERC, the Midwest ISO is committed to working with its stakeholders to resolve the unique challenges presented by incorporating wind energy into the Midwest ISO footprint. On a national level, so long as regulators and industry professionals continue to work together, wind energy will inevitably receive its fair seat at the table beside coal, nuclear, hydro and gas.
The Midwest ISO Planning Approach Overview

March 15, 2011
The continuing growth of the Midwest ISO’s value proposition depends on transmission expansion.
Midwest ISO Planning Objectives

Fundamental Goal

- The development of a comprehensive expansion plan that meets reliability needs, policy needs, and economic needs

Midwest ISO Board of Director Planning Principles

- Make the benefits of a competitive energy market available to customers by providing access to the lowest possible electric energy costs
- Provide a transmission infrastructure that safeguards local and regional reliability and supports interconnection-wide reliability
- Support state and federal renewable energy objectives by planning for access to all such resources (e.g. wind, biomass, demand side management)
- Provide an appropriate cost allocation mechanism
- Develop a transmission system scenario model and make it available to state and federal energy policy makers to provide context and inform the choices they face
The Midwest ISO’s transmission planning process is focused on minimizing the total cost of delivered power to consumers: energy, capacity, and transmission.
Midwest ISO Transmission Expansion Plan (MTEP)

- The MTEP is the culmination of all planning efforts performed by the Midwest ISO during a given planning cycle.
- This planning process is consistent with the Board of Directors Planning Principles.
- Each of the four pillars of the Midwest ISO Planning Approach informs the other, resulting in a fully integrated view of project value inclusive of reliability, market efficiency, public policy, and other value drivers across all planning horizons.
## MTEP Activities

<table>
<thead>
<tr>
<th></th>
<th>Top Down Planning</th>
<th>Bottom Up Planning</th>
<th>Interconnection Queue</th>
<th>Policy Assessment</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Description</strong></td>
<td>• Develop solutions for outstanding needs, • Test effectiveness of input plans and seek efficiencies</td>
<td>Ensure plans identified by the member Transmission Owners are sufficient to address reliability standards and form an efficient set of expansions to meet identified needs</td>
<td>Evaluate specific interconnection requests and place resulting upgrades in base expansion model</td>
<td>Analyze the impacts of changes in state or federal policy on the Midwest ISO system</td>
</tr>
<tr>
<td><strong>Examples</strong></td>
<td>Regional Generator Outlet Study, Candidate MVP Portfolio, MTEP economic analysis, Long Term Assessment</td>
<td>MTEP reliability analysis</td>
<td>Interconnection Studies, System Planning and Analysis, Detailed Planning Phase</td>
<td>EPA Regulations study, Eastern Wind Integration Transmission Study</td>
</tr>
<tr>
<td><strong>Tools</strong></td>
<td>Production Cost models (PROMOD), Generation Expansion (EGEAS), Loss of Load (MARS)</td>
<td>Loadflow models (PSS/E)</td>
<td>Loadflow models (PSS/E)</td>
<td>All</td>
</tr>
</tbody>
</table>
Objective of value based planning is to develop a wide range of future scenarios

- The “best” transmission plan may be different in each policy-based future scenario
- The transmission plan that is the best-fit (most robust) against all these scenarios should offer the most future value in supporting the future resource mix
Conditions Precedent to Increased Transmission Build

- Robust business case
- Cost allocation and recovery
- Policy consensus
## Cost Allocation Overview

<table>
<thead>
<tr>
<th>Allocation Category</th>
<th>Driver(s)</th>
<th>Allocation Overview</th>
</tr>
</thead>
<tbody>
<tr>
<td>Baseline Reliability Project</td>
<td>NERC Reliability Criteria</td>
<td>Primarily shared locally through Line Outage Distribution Factor Methodology; 345 kV and above 20% postage stamp to load</td>
</tr>
<tr>
<td>Generator Interconnection Project</td>
<td>Interconnection Request</td>
<td>Paid for by requestor; 345 kV and above 10% postage stamp to load</td>
</tr>
<tr>
<td>Market Efficiency Project¹</td>
<td>Reduce market congestion when benefits are 1.2 to 3 times in excess of cost</td>
<td>Distribute to planning regions commensurate with expected benefit; 345 kV and above 20% postage stamp to load</td>
</tr>
<tr>
<td>Multi Value Project</td>
<td>Address energy policy laws and/or provide widespread benefits across footprint</td>
<td>100% postage stamp to load</td>
</tr>
</tbody>
</table>

¹ Market Efficiency Project cost allocation methodology currently under review at the RECBTF
## Multi Value Project Myths

<table>
<thead>
<tr>
<th>Myth</th>
<th>Fact</th>
</tr>
</thead>
<tbody>
<tr>
<td>MVP’s are Socialism</td>
<td>MVP’s act to open up markets to competition</td>
</tr>
<tr>
<td>MVP’s are only about wind</td>
<td>The transmission system is non-discriminatory, all resource types have equal access to the market.</td>
</tr>
<tr>
<td>MVP’s are a FERC cram down</td>
<td>MVP’s are a response to a need identified by stakeholders. The MVP Cost Allocation Methodology was developed with all Midwest ISO stakeholders through an 18 month open and transparent process. FERC’s role is to determine if the methodology is just and reasonable.</td>
</tr>
<tr>
<td>Local only solutions are cheaper</td>
<td>Most economists agree that larger markets produce the most cost effective solutions. A combination of local and regional solutions has been shown to be best for consumers.</td>
</tr>
<tr>
<td>Every transmission line on a planning map is a reality</td>
<td>The planning maps represent a starting point for further analysis. States ultimately choose what will be built, where and when.</td>
</tr>
</tbody>
</table>
FERC Transmission Planning and Cost Allocation Proposed Rulemaking

• FERC is developing a new transmission planning and cost allocation rule to build on the principles identified in Order 890
  – Coordination; Openness; Transparency; Information Exchange; Comparability; Dispute Resolution; Regional Participation; Economic Planning Studies and Cost Allocation

• The proposed new rule seeks to address
  – Participation in a regional planning process
  – Planning for public policy, such as renewable mandates
  – Coordinated planning and improved cost sharing for interregional facilities
  – Elimination of so-called “right of first refusal” clauses
  – Increasing linkages between transmission planning and cost allocation methods
Stakeholder Interaction

Advisory Committee

- Provides guidance on MTEP report

Regional Expansion Criteria Benefits Task Force

- Provide Input on Study Process / Results

Planning Advisory Committee

- Planning Subcommittee

- Loss of Load Expectation Working Group

Subregional Planning Meetings

- Technical Study Task Force

Policy / Scope Guidance flows to Evaluation Groups / Status Updates Flow Back

Technical Guidance flows to Evaluation Groups / Status Updates Flow Back
Planning Process Results

• Between 2003 and 2009, 1,197 projects totaling $7.9 billion were approved through Appendix A. Of these projects,
  – 43.4% are in-service
  – 47.1% are planned
  – 3.1% are under construction
  – 6.4% have withdrawn

• MTEP10 included 230 projects totaling $1.2 billion in investment through 2020
  – Includes one Multi Value Project (MI Thumb project at $510 Million)
  – These projects, along with a $2.8 billion subset of Appendix A/B projects, provided more than $825 million in annual market congestion benefits beginning in 2015
MTEP 2011 Scope

- Reliability Analysis
- Loss of Load Expectation Study
- Long-term Resource Assessment
- Value Based Planning Assessment
- Congestion Analysis
- Congested Flowgate Studies
- Candidate MVP Portfolio Study
- Eastern Interconnection Planning Collaborative
- EPA Impacts Study
June 2011 Project Approvals

• Currently two projects are expected to be brought to the Board of Directors (BOD) for June 2011 for approval
  – MVP: Brookings Co. and possibly related projects
  – Baseline Reliability Project: ATC, Straits Power Flow Control

• Projects will be introduced to the BOD in April
• Content review will continue through May
• Approval will be requested in June
NOTES
LUNCHEON KEYNOTE SPEAKER
NOTES
Update on Eastern Interconnection Planning Process – Potential Impacts on the Midwest
Public Law 111-5
11th Congress

An Act

Making supplemental appropriations for job preservation and creation, infrastructure investment, energy efficiency and science, assistance to the unemployed, and State and local fiscal stabilization, for the fiscal year ending September 30, 2009, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SECTION 1. SHORT TITLE.

This Act may be cited as the “American Recovery and Reinvestment Act of 2009”.

SEC. 2. TABLE OF CONTENTS.

The table of contents for this Act is as follows:

DIVISION A—APPROPRIATIONS PROVISIONS

TITLE I—AGRICULTURE, RURAL DEVELOPMENT, FOOD AND DRUG ADMINISTRATION, AND RELATED AGENCIES
TITLE II—COMMERCE, JUSTICE, SCIENCE, AND RELATED AGENCIES
TITLE III—DEPARTMENT OF DEFENSE
TITLE IV—ENERGY AND WATER DEVELOPMENT
TITLE V—FINANCIAL SERVICES AND GENERAL GOVERNMENT
TITLE VI—DEPARTMENT OF HOMELAND SECURITY
TITLE VII—INTERIOR, ENVIRONMENT, AND RELATED AGENCIES
TITLE VIII—DEPARTMENTS OF LABOR, HEALTH AND HUMAN SERVICES, AND EDUCATION, AND RELATED AGENCIES
TITLE IX—LEGISLATIVE BRANCH
TITLE X—MILITARY CONSTRUCTION AND VETERANS AFFAIRS AND RELATED AGENCIES
TITLE XI—STATE, FOREIGN OPERATIONS, AND RELATED PROGRAMS
TITLE XII—TRANSPORTATION, HOUSING AND URBAN DEVELOPMENT, AND RELATED AGENCIES

DIVISION B—TAX, UNEMPLOYMENT, HEALTH, STATE FISCAL RELIEF, AND OTHER PROVISIONS

TITLE I—TAX PROVISIONS
TITLE II—ASSISTANCE FOR UNEMPLOYED WORKERS AND STRUGGLING FAMILIES
TITLE III—PREMIUM ASSISTANCE FOR COBRA BENEFITS
TITLE IV—MEDICARE AND MEDICAID HEALTH INFORMATION TECHNOLOGY; MISCELLANEOUS MEDICARE PROVISIONS
TITLE V—STATE FISCAL RELIEF
TITLE VI—BROADBAND TECHNOLOGY OPPORTUNITIES PROGRAM
TITLE VII—LIMITS ON EXECUTIVE COMPENSATION

SEC. 3. PURPOSES AND PRINCIPLES.

(a) STATEMENT OF PURPOSES.—The purposes of this Act include the following:
DEPARTMENT OF ENERGY

ENERGY PROGRAMS

ENERGY EFFICIENCY AND RENEWABLE ENERGY

For an additional amount for "Energy Efficiency and Renewable Energy", $16,800,000,000: Provided, That $3,200,000,000 shall be available for Energy Efficiency and Conservation Block Grants for implementation of programs authorized under subtitle E of title V of the Energy Independence and Security Act of 2007 (42 U.S.C. 17151 et seq.), of which $2,800,000,000 is available through the formula in subtitle E: Provided further, That the Secretary may use the most recent and accurate population data available to satisfy the requirements of section 543(b) of the Energy Independence and Security Act of 2007: Provided further, That the remaining $400,000,000 shall be awarded on a competitive basis: Provided further, That $5,000,000,000 shall be for the Weatherization Assistance Program under part A of title IV of the Energy Conservation and Production Act (42 U.S.C. 6861 et seq.): Provided further, That $3,100,000,000 shall be for the Weatherization Assistance Program under part D of title III of the Energy Policy and Conservation Act (42 U.S.C. 6321): Provided further, That $2,000,000,000 shall be available for grants for the manufacturing of advanced batteries and components and the Secretary shall provide facility funding awards under this section to manufacturers of advanced battery systems and vehicle batteries that are produced in the United States, including advanced lithium ion batteries, hybrid electrical systems, component manufacturers, and software designers: Provided further, That notwithstanding section 3304 of title 5, United States Code, and without regard to the provisions of sections 3309 through 3318 of such title 5, the Secretary of Energy, upon a determination that there is a severe shortage of candidates or a critical hiring need for particular positions, may from within the funds provided, recruit and directly appoint highly qualified individuals into the competitive service: Provided further, That such authority shall not apply to positions in the Excepted Service or the Senior Executive Service: Provided further, That any action authorized herein shall be consistent with the merit principles of section 2301 of such title 5, and the Department shall comply with the public notice requirements of section 3327 of such title 5.

ELECTRICITY DELIVERY AND ENERGY RELIABILITY

For an additional amount for "Electricity Delivery and Energy Reliability," $4,500,000,000: Provided, That funds shall be available for expenses necessary for electricity delivery and energy reliability activities to modernize the electric grid, to include demand responsive equipment, enhance security and reliability of the energy infrastructure, energy storage research, development, demonstration and deployment, and facilitate recovery from disruptions to the energy supply, and for implementation of programs authorized under title XIII of the Energy Independence and Security Act of 2007 (42 U.S.C. 17381 et seq.): Provided further, That $100,000,000 shall be available for worker training activities: Provided further, That notwithstanding section 3304 of title 5, United States Code, and without regard to the provisions of sections 3309 through 3318
of such title 5, the Secretary of Energy, upon a determination
that there is a severe shortage of candidates or a critical hiring
need for particular positions, may from within the funds provided,
recruit and directly appoint highly qualified individuals into the
competitive service: Provided further, That such authority shall
not apply to positions in the Excepted Service or the Senior Execu­
tive Service: Provided further, That any action authorized herein
shall be consistent with the merit principles of section 2301 of
such title 5, and the Department shall comply with the public
notice requirements of section 3327 of such title 5: Provided further,
That for the purpose of facilitating the development of regional
transmission plans, the Office of Electricity Delivery and Energy
Reliability within the Department of Energy is provided $80,000,000
within the available funds to conduct a resource assessment and
an analysis of future demand and transmission requirements after
consultation with the Federal Energy Regulatory Commission: Pro­
vided further, That the Office of Electricity Delivery and Energy
Reliability in coordination with the Federal Energy Regulatory
Commission will provide technical assistance to the North American
Electric Reliability Corporation, the regional reliability entities, the
States, and other transmission owners and operators for the forma­
tion of interconnection-based transmission plans for the Eastern
and Western Interconnections and ERCOT: Provided further, That
such assistance may include modeling, support to regions and States
for the development of coordinated State electricity policies, pro­
grams, laws, and regulations: Provided further, That $10,000,000
is provided to implement section 1305 of Public Law 110–140:
Provided further, That the Secretary of Energy may use or transfer
amounts provided under this heading to carry out new authority
for transmission improvements, if such authority is enacted in
any subsequent Act, consistent with existing fiscal management
practices and procedures.

FOSSIL ENERGY RESEARCH AND DEVELOPMENT

For an additional amount for “Fossil Energy Research and
Development”, $3,400,000,000.

NON-DEFENSE ENVIRONMENTAL CLEANUP

For an additional amount for “Non-Defense Environmental
Cleanup”, $483,000,000.

URANIUM ENRICHMENT DECONTAMINATION AND DECOMMISSIONING FUND

For an additional amount for “Uranium Enrichment Decon­
tamination and Decommissioning Fund”, $390,000,000, of which
$70,000,000 shall be available in accordance with title X, subtitle

SCIENCE

For an additional amount for “Science”, $1,600,000,000.
Eastern Interconnection Planning Collaborative

Energy Bar Association
Midwest Energy Conference
Indianapolis, IN
March 15, 2011
Presentation Topics

- Objectives of the DOE EIPC Project
- Structure
- Activities and Progress
- Future
DOE Objectives: FOA

• Facilitate the development / strengthening of capabilities to prepare analyses of transmission requirements under a broad range of alternative futures and Develop long-term interconnection-wide transmission expansion plans.

• Specific design, siting or cost allocation not in scope.
DOE Expectations: FOA

• Improved
  – Regional, inter-regional, and interconnection-level coordination on long-term electricity policy and planning
  – Quality of information available to state and federal policymakers and regulators
  – Understanding by stakeholders of Long-term transmission requirements under a wide range of futures

• Facilitation and acceleration of development of renewable or other low-carbon generation capacity
EIPC Approach

- Establishment of a Multi-Constituency Stakeholder Process
- Roll Up and Analysis of Approved Regional Plans
- Development of Inter-Regional Resource Expansion Scenarios
- Development of Inter-Regional Transmission Expansion Options
- Prepare/Submit Reports to DOE
Major Deliverables

- Roll-up and integration of regional plans for 2020
- 8 Macroeconomic “futures” with sensitivities
- 3 Future resource scenarios with fully developed transmission build-out options that meet reliability requirements
- 2 Project reports – October, 2011 (may slip) and October, 2012
EIPC Tasks: Progress

1.1: Initiate Project
- Establish EIPC
- Establish study teams

1.2: Integrate Regional Plans
- Aggregate models
- Inter-regional scenarios
- Expand

1.3: Production Cost Analysis of Regional Plans
- Multiple sensitivities (e.g., fuel, capital, load)

1.4: Macroeconomic Scenario Definition
- Stakeholder consensus
- Multiple scenarios

1.5: Macroeconomic Analysis
- Multiple scenarios
- Informs policies/stakeholders
- High-level T sensitivities

1.6: Expansion Scenario Concurrence
- EIPC scopes scenarios (input from 1.5 input & such states)
- SSC guidance
- States (Part B) endorse

1.7: Inter-regional Expansion Options
- Modeling & initial analysis
- Transmission/other taxes
- Interconnection facilities considered (high-level)

1.8: Reliability Review
- Consistent with NERC reliability criteria

1.9: Production Cost Analysis of Inter-regional Expansion Options
- Multiple sensitivities (e.g., fuel, capital, load)

1.10: G & T Cost Estimates
- High level cost estimates for generation and transmission expansion options.

1.11: Review of Results
- Draft results reviewed with stakeholders
- Stakeholder input incorporated

1.12: Phase I Report
- Posted and to DOE by 6/30/11
- Supporting files on public website

Roll-up of Regional Plans
Inter-Regional Expansion Scenarios
Inter-Regional Transmission Options

Eastern Interconnection Planning Collaborative
Stakeholder Steering Committee

• **Purpose:** strategic guidance to the analysts
  – Scenarios to be modeled
  – Modeling tools to be used
  – Key assumptions for the scenarios,
  – Strive to achieve consensus
Stakeholder Steering Committee

• **Structure**
  – Generation Owners & Developers – 3
  – Transmission Owners & Developers – 3
  – Other Suppliers – 3
  – Public Power-TDUs – 3
  – End Users – 3
  – NGOs – 3
  – States (EISPC) -10
  – Canada -1

• **Currently developing Futures and sensitivities**
Stakeholder Developed Futures Descriptions 1-4

1. Business as Usual
3. Federal Carbon Constraint: State and regional implementation and choice
4. Aggressive Energy Efficiency, Demand Response, Distributed generation and Smart Grid
Stakeholder Developed Futures Descriptions 5-8

5. National RPS – Top-Down Implementation
6. National RPS – State/Regional Implementation
7. Nuclear Resurgence
8. Combined Federal Climate and Energy Policy
9. Clean Energy Standard 2035
Development of the Build-Outs

• EIPC is developing mechanisms to project transmission for the 3 selected Futures
• Proposed plans of the Planning Authorities that were too uncertain for inclusion in the Stakeholder Baseline are likely initial adds
• Most of 2012 will be devoted to this effort
Parallel Regional Planning Processes

- Similar scenario-based planning processes underway in some areas
- Some regional processes ahead of the EIPC process by a few years
  - Policy considerations / consensus
  - Futures / robustness
  - Aggregate regional needs / benefits
Regional Plans That May Align

- Candidate MVP Plans
- BAU Scenario: 20 year Regional RPS Reqs
Regional Plans That May Align

- More robust 765 kV RGOS Plan
- Possible starting point for National RPS
Coordination after DOE Project

- **FERC Observations in NOPR**
  - Few processes in place to analyze interregional solutions as alternatives to regional transmission plans
  - Not clear whether DOE FOA would result in a regular process for identifying alternatives to existing Order No. 890 Plans
  - No intent to interfere with the efforts already underway in ARRA-funded transmission planning initiatives
FERC Proposal and EIPC

• Require each transmission provider to coordinate with the providers in each of its neighboring transmission planning regions
• Filed interregional transmission planning agreements
• EIPC has an agreement in place intended to be ongoing
Applying the EIPC Results

EIPC

- EIPC Agreement
- Interconnection-wide
- Coordinated Models
- Long range concepts

MISO

PJM

INTER-REGIONAL

INTERCONNECTION

MISO

REGIONAL

- JOAs
- Seams planning
- Coordinated models
- Coordination of Regional Plans

- Order 890
- Regional Needs
- Regional Plan Development
Cost Allocation?

- Beyond scope of DOE project
- FERC NOPR Proposals
  - Require transmission providers in each pair of neighboring transmission planning develop method for allocating between the two regions
    - New facilities
    - Located within both regions
    - Eligible for interregional cost recovery pursuant to the required interregional planning agreement
## Project Related Meetings

<table>
<thead>
<tr>
<th>Meeting</th>
<th>Current Dates</th>
<th>New Dates?</th>
</tr>
</thead>
<tbody>
<tr>
<td>SSC Meeting</td>
<td>2/7/11 – 2/8/11</td>
<td>Complete</td>
</tr>
<tr>
<td>Joint SPWG/MWG</td>
<td>2/8/11 – 2/9/11</td>
<td>Complete</td>
</tr>
<tr>
<td>EISPC Meeting</td>
<td>2/28/11 – 3/2/11</td>
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Questions and Discussion
1. **What is NERC’s roles in the industry’s planning process?**

NERC’s mission is to ensure that the bulk power system in North America is reliable. Meeting this objective involves in-depth, coordinated planning with industry to ensure the system performs reliably under normal and abnormal conditions.

2. **How does NERC perform an independent reliability assessment of the North American bulk power system?**

NERC’s primary role in providing reliability assessment is to identify areas of concern to the reliability of the North American bulk power system and to make recommendations for their remedy. To achieve this, NERC follows certain *Rules of Procedure*:

- Review, assess, and report on the overall electric generation and transmission reliability (adequacy and operating reliability) of the interconnected bulk power systems, both existing and as planned.

- Assess and report on the key issues, risks, and uncertainties that affect or have the potential to affect the reliability of existing and future electric supply and transmission.

- Review, analyze, and report on Regional self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific Regional concern.

- Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on bulk power system reliability.

- Investigate, assess, and report on the potential impacts of new and evolving electricity market practices, new or proposed regulatory procedures, and new or proposed legislation (e.g. environmental requirements) on the adequacy and operating reliability of the bulk power systems.

3. **How is information gathered for the reliability assessments?**

NERC’s assessments are prepared with support from the Reliability Assessment Subcommittee (RAS) under the direction of NERC’s Planning Committee (PC). The reports are based on data and information submitted by each of the eight Regional Entities submitted in March, May and September each year and periodically updated throughout the process. Instructions on data submittal and timely subjects for group development within the self-assessments are provided to each Regional Entity approximately three-to-five months prior to submittal of the data and narratives. Any other data sources consulted by NERC staff are identified in the report.
4. What are the measures used to perform the assessment?

NERC uses an active peer review process in developing reliability assessments. The peer review process takes full advantage of industry subject matter expertise from many sectors of the industry. This process also provides an essential check and balance for ensuring the validity of the information provided by the Regional Entities.

Each Region prepares its data and a self assessment. Each of the Regional self-assessments is assigned to two-to-four RAS members from other Regions for an in-depth and comprehensive review of the data and information. Reviewer comments are discussed with the Regional Entity’s representative and refinements and adjustments are made as necessary. The Regional self-assessments and data are then subjected to scrutiny and review by the entire subcommittee. This review ensures members of the subcommittee are fully convinced that each Regional self-assessment and data is accurate, thorough, and complete. The report is also reviewed by the Operating Committee (OC), while the entire document, including the Regional self-assessments, is then reviewed in detail by the Member Representatives Committee (MRC) and NERC management. The report is endorsed by the PC before being submitted to NERC’s independent Board of Trustees for final approval (See Appendix II for organization charts). This comprehensive vetting process ensures complete stakeholder agreement on NERC’s independent assessment and the self-assessment from the Regional Entities, as well as supports the mission of NERC as a self-regulatory organization.

5. What are the recommendations going forward to improve reliability assessments?

NERC has been pursuing an improved definition of adequacy to address both the issues of sufficient generation capacity and its delivery to end users. One way of addressing this larger definition of adequacy is to define it in terms of how uncertainty is dealt with in the various planning processes. Adequacy becomes a measure of the level of confidence the operator and planner have that the bulk power system as modeled in studies can meet performance requirements in real time.
NOTES
A New World Order?
How Gas and Renewable Generation May Soon Stack Up
Reflections on the Integration of Wind Energy into the Power Grid

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Abstract

This paper notes that the large scale integration of wind into the power system is likely to have only a minor impact on carbon emissions. It is also noted that wind energy is not inexpensive. There is peer reviewed literature from Europe that the wind turbines can create visual disamenities that are economically relevant. Wind energy is highly variable from hour to hour. The production levels are difficult to forecast and thus its large scale integration into the power grid presents a challenge to electric power reliability.

1. Introduction

According to the United States Energy Information Administration, the share of electricity generation in the United States from wind turbines was approximately 1.8 percent in 2009. Broad political support exists for increasing substantially this share. Some policymakers are in favor of attaining a 20 percent wind penetration level by 2030. Given the magnitude of this proposed expansion, it is prudent to consider seriously its potential consequences.

This paper notes that the large scale integration of wind into the power system is likely to have only a minor impact on carbon emissions. It is also noted that wind energy is not inexpensive. There is peer reviewed literature from Europe that the wind turbines can create visual disamenities that are economically relevant. Wind energy is highly variable from hour to hour. The production levels are difficult to forecast and thus its large scale integration into the power grid presents a challenge to electric power reliability.

2. The Large Scale Integration of Wind Energy into the Power Grid is Expected to have only a Minor Impact on Carbon Emissions.

There are no direct carbon emissions associated with the production of electricity from wind turbines. In contrast, the production of electricity using coal gives rise to approximately two pounds of CO₂ per kilowatt-hour (kWh) while a modern natural gas combined cycle plant has a carbon “footprint” of about 0.80 pounds per kWh. Based on these statistics, the environmental benefits of wind energy are maximized when wind energy displaces coal. However, the operators of power grids dispatch generating plants based on economics, not carbon intensity.

1 For example, in October 2008, the California Public Utilities Commission and the California Energy Commission recommended a 33% renewable energy requirement as a key strategy to reduce greenhouse gases. The plan, if implemented, would increase the wind energy capacity available to the California Independent System Operator (ISO) by almost 500 percent by 2020 with wind energy capacity accounting for approximately 18 percent of installed nameplate capacity (Hawkins, 2008). The European Union has a goal of 20 percent renewable energy by 2020 with wind energy serving as a key source of the increase.

2 Based on data reported by the United States Energy Information (2010).
System operators base the dispatch of nonwind generation on private marginal costs with priority being given to generating units with the lowest private marginal costs (private marginal cost is the change in generation cost paid by the generating firm when output rises by one unit). An increase in scheduled wind energy will therefore reduce expected generation from higher private marginal cost generating units. While natural gas combined cycle plants are more efficient in power conversion than coal plants, the reality is that the short run private marginal costs of generating a MWh from natural gas is generally more than the short run private marginal costs of generating a MWh of electricity from coal because natural gas is more expensive than coal on an energy equivalent basis. Thus, in the absence of a carbon tax or cap-and-trade legislation (either of which would discourage the production of electricity from carbon intensive fuels), an increase in wind energy has the unintended consequence of largely displacing natural gas, the cleanest fossil fuel. One implication of this is that increases in wind energy penetration may have only a modest effect on carbon emissions. A 2008 study by the United States Department of Energy projects that carbon emissions from the electricity sector in 2030 will be substantially above the target level even if the wind penetration level rises to 20 percent (Figure 1).

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3 For evidence on this point, see Figure 4 of the 2008 Midwest State of the Market.
4 This point about wind displacing natural gas has also been made by a recently released study by MIT. The study can be downloaded at http://web.mit.edu/ceepr/www/publications/Natural_Gas_Study.pdf
One caveat of this point is that wind levels less than forecasted may induce the system operator to dispatch turbines fueled by natural gas.
3. Wind Energy is not Cheap

When the cost of electricity transmission is ignored, the United States is believed to have more than 8,000 Gigawatts (GW) of wind resources that the industry estimates can be developed at a cost of less than or equal to approximately $80 per MWh. When transmission costs are factored in, only about 600 GW of resources could be available at a delivered price less than $100 per MWh with the vast proportion of this amount requiring a price of more than $60 per MWh (Figure 2). To put these supply prices in perspective, the 2008 average day-ahead wholesale

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7 This estimate excludes the effect of the production tax credit and renewable energy credits on the supply price.
price in the Wisconsin-Upper Michigan area of the Midwest Independent System Operator (ISO) was $54.30 per MWh.\textsuperscript{8}

One dramatic example of the economics of wind energy is the offshore Cape Wind project in Cape Cod, Massachusetts. Cape Wind and National Grid have filed a contract with the Massachusetts Department of Public Utilities under which National Grid would purchase from Cape Wind 50 percent of the project’s output for $207 per MWh.\textsuperscript{9} This is almost five times the Massachusetts’ 2009 wholesale price of approximately $42 per MWh and thus represents a very high cost approach to reducing carbon emissions.\textsuperscript{10} A cheaper approach to reducing carbon emissions would be to stimulate the substitution of natural gas for coal.\textsuperscript{11}

\textsuperscript{8} Midwest ISO 2008 State of the Market, p. 37.
\textsuperscript{9} http://www.windtoday.net/articles/National_Grid_and_Cape_Wind_Sign_Power_Purchase_Contract_-93520.html
\textsuperscript{10} The price of $42 per MWh is based on 2009 hourly price data reported by ISO England. This data are available at http://www.iso-ne.com/markets/hstdata/znl_info/hourly/index.html
\textsuperscript{11} Minimizing the total cost of abatement for a desired level of emissions reduction from the power sector requires that marginal abatement costs be equalized across emission sources. There is no reason to believe that this technical condition for cost minimization is satisfied when renewable fuel mandates are imposed. Given the differences in carbon intensity between natural gas and coal, a cost minimizing abatement policy implies a substitution of natural gas for coal. For more on this point see the recently released study by MIT which is available for download at http://web.mit.edu/mitei/research/studies/report-natural-gas.pdf
Figure 2. The Supply Costs of Wind Energy

Source: DOE (2008), p. 9

Note: the “Classes” in the figure are categories of wind intensity. For information on wind classes, please see [http://www.eia.doe.gov/cneaf/solar_renewables/page/wind/wind.html](http://www.eia.doe.gov/cneaf/solar_renewables/page/wind/wind.html)
4. Wind Turbines can Create Visual Disamenities.

There is published peer-reviewed evidence from Europe that a significant number of individuals would be willing to pay for wind turbines to be less visible. For example, Bergmann et al. (2006) have reported evidence that respondents in a survey were willing to pay 12 Euros/year for reducing landscape impacts. Ladenburg and Dubgaard (2007) have reported evidence that there are significant preferences in Denmark for reducing the visual disamenities from offshore wind farms. Specifically, they report an average willingness to pay of 46, 96, and 122 Euros/household/year for having a wind project located at 12, 18 and 50km from the coast of Denmark as opposed to 8 km.

These results are not consistent with a recent study by Hoen et. al, (2009) that found no evidence of any adverse impact of wind energy development on property values in the United States. However, their results are open to question given that the wind projects were selected for analysis based in part on the advice of wind energy stakeholders. Consistent with the suspicion that the sample was not representative, there are no observations in the sample in which the house in question had a premium view in the absence of the wind turbines and an extreme view of the wind turbines.

There are other issues with the study by Hoen et. al. (2009). For example, in one of their models (pages 52-54 of the report) the natural logarithm of the sales price was regressed on a number of control variables and two series of binary variables. The first series of binary variables represent the intensity of the view of the wind turbines while the second series represent the quality of the view from the house in the absence of the wind turbines. The authors report evidence that the quality of the view from the house in the absence of the wind turbines affects the sales price but that intensity of the view of the turbines does not. One acknowledged shortcoming of this model is that it presumes that the impact of wind turbines on the dependent variable is independent of the quality of the view in the absence of the wind turbines. The authors attempt to address this shortcoming by creating an interaction variable which equals the product of the two series of binary variables. This is akin to multiplying apples and oranges since the product of the two series does not represent a unique combination of the two measures. The coefficient on this improperly constructed variable is negative and statistically significant at the 10 percent level indicating modest statistical support for the hypothesis that wind turbines can have an adverse impact on property values. One can only wonder what the statistical significance would be if the sample were representative and the interaction effect were properly modeled.

Hoen et. al. (2009) also examine whether wind turbines create a “nuisance stigma” in the sense that sound and shadow flicker may depress the values of homes that are in close proximity to wind turbines. In one of the models aimed at testing for this, they create a number of binary

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12 This point is acknowledged on page 11 of Hoen et. al. (2009)
13 The authors concede this point in footnote 90 on page 53.
variables to represent the distance between the house and the closest wind turbine. The categories are as follows: distance < 3000 feet, 3000 feet \(\leq\) distance < one mile, one mile \(\leq\) distance < three miles, three miles \(\leq\) distance < five miles, distance \(\geq\) five miles. The coefficients on the first two binary variables are negative but are statistically insignificant. Given this statistical insignificance, the authors report that there is no evidence of “nuisance stigma.”

Closer inspection of these results is warranted. There are 4,937 observations in the sample but there are only 67 observations in the first distance category, i.e. distance < 3000 feet. This is the category that one would expect nuisance stigma, if it exists, to be evident. The authors chose 3000 feet as a cutoff for this category “because it was the closest cutoff that still provided an ample supply of data for analysis.”\(^\text{14}\) Given that sound and shadow flicker may be irrelevant when distance exceeds say, 2000 feet, one can only wonder what the statistical significance of the estimated coefficient would be if more data had been employed and the cutoff of the first distance category were 2000 feet as opposed to 3000 feet.

Hoen et. al. (2009) examine whether wind turbines create “area stigma,” which they define as “as a concern that the general area surrounding a wind energy facility will appear more developed, which may adversely affect home values in the local community regardless of whether any individual home has a view of the wind turbines.”\(^\text{15}\) The authors test for area stigma using a number of econometric specifications. In each of these specifications, area stigma is tested for using variables that represent distance of the house from the nearest wind turbine. No evidence of “area stigma” is obtained.

A few remarks are in order. Suppose there are two identical houses, ABC and XYZ located in two different counties. They are both located one mile from the nearest turbine. But the turbine corresponding to ABC is part of a 100 turbine wind energy facility while the turbine corresponding to XYZ is part of a three turbine facility. The models estimated by Hoen et. al. (2009) would treat these two observations as identical when in fact they are not in terms of wind turbine density. Accordingly, the reported tests for “area stigma” are not convincing.

The solution to this problem would to include turbine density (e.g. turbines per square mile for the zip code) as an explanatory variable. When including this variable, one would want to test for threshold effects since area stigma may only be evident once a certain level of turbine density is attained.

\(^{14}\) footnote 38 on page 15.
\(^{15}\) Heon(2009), p 69.
5. Wind Energy is Difficult to Forecast and thus its Integration into the Power Grid Presents a Challenge to Electric Power Reliability

Under currently technology, it is not economically viable to store large quantities of electricity. Moreover, the stability of a power grid requires that the supply of electricity equal demand, on a near-instantaneous basis, at all times. Given these realities, wind energy can represent a challenge to operations because production levels are largely uncontrollable.\(^{16}\) There is also evidence in the case of ERCOT (Electric Reliability Council of Texas), the system operator for the vast proportion of Texas, that wind energy production levels are difficult to forecast. This is quite apparent in the case of January 2010 (Figure 3). Figure 4 presents a histogram of the forecast errors over the period 13 June 2009 through 28 February 2010. Observe that the forecasts are biased in the sense that the forecasting system tends to overpredict the actual level of wind energy.

It is sometimes suggested that the uncertainty in wind power forecasting is not necessarily greater than the uncertainty in forecasting load, i.e. consumption. Analysis of the data does not support this view. For example, the root-mean-squared errors of the day-ahead wind forecasts in ERCOT were more the 50% percent of mean wind energy production over the period 13 June 2009 through 28 February 2010.\(^{17}\) To put this measure in perspective, the root-mean-squared errors of the load forecasts in the Midwest ISO are approximately 3.5 percent of mean load.\(^{18}\)

\(^{16}\) Wind generation can be reduced but the system operator cannot direct that wind generators increase their output.

\(^{17}\) The root-mean-square-error is a measure the average of the square of the "error". Specifically, it equals the squared root of the average squared error.

\(^{18}\) This measure was calculated by the author using hourly data from the Midwest ISO over period 1 January 2009 through 30 December 2009.
Figure 3. Forecasted and Actual Wind Energy Production Levels in ERCOT, January 1-31, 2010

Source: Based on data reported by ERCOT. Note: the day-ahead forecasts in the figure are ERCOT’s 9:00 AM forecast.
Figure 4. A Histogram of Day-Ahead Wind Forecasting Errors in ERCOT, 12 June 2009-28 February 2010.

Source: Based on data reported by ERCOT. Note: the day-ahead forecasts in the figure are ERCOT’s 9:00 AM forecasts.
There is evidence that both the variability in wind energy production and the forecast errors in ERCOT have adverse operational impacts.\textsuperscript{19} This may be tolerable when the wind energy’s share of total generation is low but may represent a major challenge to operations when higher penetration levels are attained.

It is sometimes asserted that the advances in forecasting wind in Europe over the past decade makes it possible to achieve high levels of wind integration with little or no effort.\textsuperscript{20} Unfortunately, the data from Germany, a country with one of the world’s highest levels of wind integration, does not entirely support this view. True, the errors have declined but they remain quite large. As recently as 2005, the root mean squared errors in 50Hertz, one of Germany’s

\textsuperscript{19} See Forbes, Stampini, and Zampelli (2010a).
\textsuperscript{20} For example, see EWEA, (2007).
largest power grids (formerly known as Vattenfall) were approximately 50 percent of mean wind energy production. The root mean squared errors in 2009 were approximately 35 percent of mean wind energy production.\(^{21}\) The 2009 wind forecasting errors in the Amprion and Transpower systems (formerly known as RWE and E.ON Netz), the other two major transmission systems in Germany, are of the same order of magnitude. The wind forecasting errors in the Republic of Ireland are also approximately 35 percent of mean wind energy production.\(^{22}\)

The Midwest ISO does not release sufficient data to be able to meaningfully report on the wind forecasting errors within its control area.\(^{23}\) It is unlikely that the wind forecasting errors are significantly less than those in Germany. In any event, consistent with the view that the errors are probably very large, the wind energy production levels are highly variable (Figure 5).

Wind energy production levels in the Midwest ISO averaged 1,678 MWh per hour in 2009 which was approximately equivalent to 2.7 percent of average system load. This level of wind energy production was approximately 74 percent higher than in 2008. Production during the first five months of 2010 was 2,416 MWh per hour, up approximately 35 percent over the period in 2009 and almost three times the levels during the same period in 2008.\(^{24}\) Much of this increase is believed to be driven by renewable energy requirements by the various states and the 2.1 cent per kWh production tax credit from the Federal government during the first 10 years of production.\(^{25}\)

There are operational challenges arising from the boom in Midwest wind energy production. As in ERCOT, wind generation is often negatively correlated with load and thus the value of the additional generation is open to question. Moreover, in the Midwest ISO, wind generation resources are currently exempt from all Revenue Sufficiency Guarantee (RSG) costs, including must-run, deration, excessive energy, and deficient energy deviations.\(^{26}\) Ironically, it is believed

\(^{21}\) Despite the decline in the relative error, there is evidence that wind energy remains a challenge to operations. Please see Forbes, Stampini, and Zampelli(2010b).

\(^{22}\) Calculated by the author based on data downloaded from Eirgrid, the system operator in the Republic of Ireland.

\(^{23}\) Using freely available data from the website of the Midwest ISO, the author has been able compare hourly forecasted wind energy levels with actual hourly levels for 14 days in June 2010. Based on these data, which may not be representative given that there are only 336 observations, the root-mean-squared error of the wind forecasts is approximately 34 percent of mean wind energy production.

\(^{24}\) Calculated by the author based on hourly data downloaded from the Midwest ISO.

\(^{25}\) The American Recovery and Reinvestment Act provides a three-year extension of the production tax credit (PTC) through December 31, 2012. Under the act, wind project developers can choose to receive a 30% investment tax credit (ITC) in place of the PTC for facilities placed in service in 2009 and 2010, and also for facilities placed in service before 2013 if construction begins before the end of 2010.

\(^{26}\) Midwest ISO 2008 State of the Market, p. 60. RSG payments are payments made to generators committed by the Midwest ISO when the market revenues are not sufficient to cover the generators’ as-offered production costs. Generation resources that are not committed in the
that the variability in wind output can increase RSG costs since additional conventional generation resources are required to manage the variability.  

The Midwest ISO is well aware of the operational challenges associated with higher wind penetration levels. In its words,

“Although wind provides substantial environmental benefits relative to most conventional generation, it also presents significant operational challenges that need to be addressed before larger amounts of wind generation can be integrated into the market.”

The Midwest ISO is to be applauded for its candor. However, given the strong political support in favor of increased wind energy penetration, it may be difficult for the ISO to impose a moratorium on new wind energy projects even if the operational challenges are not resolved. It is more likely that the system operator will seek to impose rules that would penalize wind energy producers for the variability and relative unpredictability of wind energy. Such rule changes have already been proposed in Texas. This is also the reality in Denmark, a country where wind energy accounts for approximately 20 percent of load. This could significantly adversely affect the economics of wind energy production for wind generating units that are no long eligible for the production tax credit (the production tax credit only applies for the first ten years), especially in states such as Wisconsin where the wind resources are marginal. Some wind energy projects could prematurely cease production as a result. If the financial resources available for day-ahead market but must be dispatched to maintain reliability (gas turbines) are the most likely recipients of these payments.

Ibid.


The market monitor in the Midwest ISO has in fact recommended that “…payments for RSG and other services (e.g., reserves, regulation) should be assessed to wind generators in accordance with the costs that such generators cause in order to provide these suppliers efficient operating and investment incentives.” (Midwest ISO, p. 64)

See Gold (2009)

In Denmark, wind producers offer their production for sale in the day-ahead spot market and are penalized for the difference between actual and scheduled output depending on the overall market imbalance. For example, if there is a shortage in the overall market and generation from wind power plants is lower than offered, then upward regulating power will need to be dispatched by the system operator in order to maintain the overall power balance. In this case, the wind producer will receive a price that is less than the day-ahead spot market price (other producers who are in deficit will also be penalized). For more on this point, see http://www.wind-energy-the-facts.org/en/part-3-economics-of-wind-power/chapter-5-wind-power-at-the-spot-market/power-markets.html

According to the EIA, the vast proportion of Wisconsin has class 2 wind resources. This category of wind resources is considered marginal. (http://www.eia.doe.gov/cneaf/solar.renewables/ilands/fig13.html)
the decommissioning of inactive turbines are inadequate, this could leave some communities with views of abandoned or largely inactive wind turbines.⁳³

6. Conclusion

The integration of wind energy into the power grid is perceived as an important metric of action to reduce carbon emissions. However, simply having more wind energy on the power grid may not result in cost effective reductions in carbon emissions. To reduce carbon at the least cost to society, firms need incentives to reduce emissions from the most carbon intensive fuels. It is not a socially desirable outcome to have carbon reductions undermine the reliability of the power grid. At a very minimum, consideration should be given to slowing the rapid pace of wind energy development before the operational challenges that the Midwest ISO faces become intolerable. Absolutely no weight should be attached to the findings of Hoen (2009) who report no relationship between wind turbines and property values. Instead, following from Ladenburg and Dubgaard (2007), consideration should also be given to mitigating the impacts of turbines on the welfare of individuals in the surrounding communities.

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³³ There are of course requirements in Wisconsin that totally inactive turbines be decommissioned. However, it may be possible for the owner of an unprofitable turbine to delay the decommissioning costs by running the turbine at a low level.
References


Midwest ISO 2008 State of the Market. http://www.midwestiso.org/publish/Folder/10b1ff_101f945f78e_-75e40a48324a?rev=1
Abstract - In response to the very real challenge of climate change, the share of electricity generation from wind turbines is expected to increase substantially over the next few decades. Yet, wind reliability poses a challenge to grid operators, and the induced balancing actions may hamper the effect of renewable energy production on the reduction of overall carbon emissions. This is the focus of our paper. First, we show that the errors in forecasting wind energy are considerably larger than generally recognized. Second, we estimate an econometric model that assesses the relative importance of those factors that induce a system operator to take actions aimed at maintaining system reliability, specifically the re-dispatch of generation and the modification of injections into the transmission system. The analysis focuses on the 50Hertz transmission control area in Germany (formerly known as Vattenfall) from 1 November 2008 through 31 December 2009, a period over which wind energy accounted for approximately 20.4 percent of consumption – a value consistent with those being set by regulators in both Europe and United States. The empirical analysis indicates that the higher the wind energy share of forecasted demand, the more likely it is that a system operator will need to undertake measures to ensure “safe, secure, and reliable operations”. More specifically, the presence of wind power raises the probability of such measures by a factor of 15 relative to the counterfactual case of the absence of wind power.

Keywords: Climate Change, Renewable Energy, Wind Energy, Wind Forecasting, 50Hertz, EnWG.

JEL Codes: Q2, Q4, Q5
1. Introduction

Because of the environmental concerns associated with fossil fuel use, there is considerable support for increasing the share of electric power generation attributable to wind energy. For example, in October 2008, the California Public Utilities Commission and the California Energy Commission recommended a 33 percent renewable energy requirement as a key strategy to reduce greenhouse gases. The plan, if implemented, would increase the wind energy capacity available to the California Independent System Operator (ISO) by almost 500 per cent by 2020 with wind energy capacity accounting for approximately 18 percent of installed nameplate capacity (Hawkins, 2008). The European Union has a goal of 20 percent renewable energy by 2020 with wind energy serving as a key source of the increase needed to meet the target.

In light of these advocated increases in the share of generation from wind turbines, it is prudent to consider their potential contribution to meeting the goal of significant reductions in CO2 emissions. Is there reason to believe that the proposed increases represent “low hanging fruit” in terms of the cost of carbon abatement or are the government directed proposed increases in wind energy capacity inconsistent with a “first-best” policy? As important is the related issue of wind energy’s effect on power grid operations, given that wind is a “variable” source of electricity supply and that the stability of an electricity control area requires that the supply of electricity match electricity demand at all times, not just on average.²

The purpose of this paper is threefold. First, we investigate whether the widespread use of subsidies to wind power is likely to lead to an optimal solution in terms of overall power production and carbon emissions. Second, we show that wind power forecasting errors

² The complications due to the intermittency of a power source and the requirement that electricity production always equal electricity consumption are a consequence of the fact that, at this time, there is no economically feasible way of storing electric power.
remain large despite statements asserting that operators have improved their forecasting models. Third, we show that high levels of wind penetration significantly increase the likelihood that grid operators will need to engage in actions that ensure the balancing of electricity demand and supply. Summarily, we find that subsidies to wind power (i) lead to an excessive production of power in the aggregate, (ii) induce a suboptimal reduction in power from traditional sources and hence in carbon emissions, and (iii) increase the challenge for network operators in balancing demand and supply, raising the likelihood of balancing actions by a factor of 15 in the 50Hertz control area.

We use high frequency data from the 50Hertz transmission system operator (TSO) in Germany (http://www.50hertz-transmission.net/cps/rde/xchg/trm_de/hs.xsl/index.htm; formerly named Vattenfall) from 1 November 2008 through 31 December 2009. Over this period, wind energy accounted for approximately 20.4 percent of production in the area covered by the 50Hertz network. This makes our contribution particularly relevant to the policy debate since a 20 percent wind power share is very much in line with the targets being set by regulators in both Europe and United States. The paper is also unique in that the 50Hertz data has not been exploited by other researchers to explore these issues.

The remainder of the paper is organized as follows. Section 2 presents a simple theoretical model demonstrating that in general subsidies to wind power cannot lead to a first best solution in terms of energy production and carbon emissions. Section 3 presents the data, the model, and the methodology used to analyze the impact of wind energy penetration on the need for balancing actions by the system operator. The measurement and magnitude of forecasting errors are covered in section 4 while section 5 discusses the results of the multivariate analysis of the impact of forecasting errors on the likelihood of balancing actions in the 50Hertz network. Section 6 offers a brief summary and some concluding remarks.
2. Can Subsidies to Green Energy Lead to a First-Best Optimum?

An economically rational society should adopt policies designed to achieve environmental goals at least possible cost. In turn, this implies that to minimize the cost of reducing carbon emissions from the power sector, emissions should be cut such that the marginal abatement costs are equalized across all carbon sources within the sector. Under cap-and-trade, this can be achieved with profit maximizing firms and a competitive carbon market. Firms would find it profitable to reduce carbon emissions until the marginal abatement costs equal the price of carbon. With a uniform carbon price within the power sector, marginal abatement costs would be equalized across generating units both within and across firms, thus minimizing the total abatement costs of achieving the targeted emissions reduction.

Unfortunately, cap-and-trade legislation remains stalled in the United States. While Europe, to its credit, has implemented a cap-and-trade scheme, the level of permits issued in 2009 actually exceeded emissions, leaving the carbon price in 2009 well below the threshold needed to shift electricity generation away from coal. For some, the failure to pass and/or implement suitable cap-and-trade policies is not particularly disappointing. For example, Bjorn Lomborg (2009), author of *The Skeptical Environmentalist* and *Cool It*, argues that society should focus its efforts on making solar and wind energy “competitive” with electricity generated from fossil fuels through systems of subsidies and/or tax credits.

Unfortunately, sole reliance on policies designed to stimulate additional supplies of green energy with subsidies and tax credits will not lead to an efficient level of carbon emissions except in the highly implausible case of perfectly inelastic demand.

To see this, assume there are two sources of power, Dirty Power (DP) and Green Power (GP). For simplicity, assume that the marginal social costs of GP (MSC\textsubscript{GP}) equal its marginal private costs (MPC\textsubscript{GP}), i.e., there are no negative externalities and hence zero
spillover costs associated with the production of GP. In contrast, assume that the marginal social costs of DP (MSC\textsubscript{DP}) are considerably higher than its associated marginal private costs (MPC\textsubscript{DP}). That is, society at large bears a cost in the production of DP, pollution, for which the producers of DP are not held accountable. Assume further that MSC\textsubscript{GP} is less than MSC\textsubscript{DP} but higher than MPC\textsubscript{DP}. The situation is depicted graphically in Figure 1. Under laissez-faire, the market supply curve of power would be $S^{LF}$, the horizontal sum of the GP and DP supply curves.\textsuperscript{3}

Market equilibrium under laissez-faire is shown in Figure 2. The equilibrium price and quantity are $P_{LF}$ and $Q_{LF}$, respectively. The quantities of dirty and green power produced are $Q_{DP,LF}$ and $Q_{GP,LF}$, respectively, with total power produced given by $Q_{LF} = Q_{DP,LF} + Q_{GP,LF}$.

The first best optimal price ($P^*$) and quantity ($Q^*$) are identified in Figure 3. As required, at this point the marginal social cost of producing electricity equals the price that consumers are willing and able to pay. Observe that the negative externality from the production of dirty power is costly enough such that the optimal quantity of dirty power is zero, i.e. only green power should be produced at the social optimum\textsuperscript{4}. Moreover, it is important to note that $Q^* < Q_{LF}$, i.e., the total amount of power produced is less than the amount produced under the laissez-faire equilibrium.

Now consider a green power subsidy (Figure 4).\textsuperscript{5} This would induce a rightward shift in the supply of green power (from $S_{GP}^{LF}$ to $S_{GP}^{LF-SS}$) and pivot the total supply curve down to the right (from $S_{DP}^{LF} + S_{GP}^{LF}$ to $S_{DP}^{LF} + S_{GP}^{LF-SS}$). The supply of dirty power meanwhile would not shift since suppliers of dirty power are assumed ineligible for the subsidy. The equilibrium price of power would decline (to $P_{SS}$) while total output, which as emphasized above already exceeds $Q^*$, would rise even further to $Q_{SS}$. Because of the lower price, $Q_{DP}$

\textsuperscript{3}Note that $S^{LF}$ will coincide with $S_{DP}^{LF}$ when price is less than or equal to $P_0$.

\textsuperscript{4}This is a simplification used only to make identification of the optimum easier.

\textsuperscript{5}The analysis reaches the same conclusions whether the subsidy is given for green power production or green power consumption.
would fall. Yet, the general result is that subsidies to green power cannot be expected to lead to a first-best optimum either in terms of emissions reductions or in terms of the resources allocated to overall power production. In contrast, a well-designed Pigouvian tax or cap-and-trade program would yield a first-best outcome.

Despite the conclusion that subsidies aimed at increasing the use of renewable energy technologies are generally not “first best”, such policies have indeed been adopted in a number of countries especially with regards to wind power. The important task at hand now is to assess the consequences of such substantial penetration of wind power into electricity grids, especially as far as concerns the consequences for reliability. It is to this task that we now turn.
Figure 1. Hypothetical Marginal Cost Curves for Dirty and Green Power

![Figure 1](image1.png)

Figure 2. The Market Equilibrium under Laissez-Faire

![Figure 2](image2.png)
3. Data and Methodology

We use high frequency data from the 50Hertz network (http://www.50hertz-transmission.net/cps/rde/xchg/trm_de/hs.xsl/index.htm) over the period 1 November 2008.
through 31 December 2009. 50Hertz is the system operator of the 380/220 kilovolt transmission grid throughout the German Federal States of Thuringia, Saxony, Saxony-Anhalt, Brandenburg, Berlin, Mecklenburg-Western Pomerania, and Hamburg (Figure 5). Within the 50Hertz network, wind farms had a capacity of about 10,000 MW in October 2009 representing more than 40 percent of Germany’s total wind energy capacity (50Hertz, 2010) and wind energy accounted for a 20.4 percent share of total electricity production. According to the company’s 2009 annual report, wind energy capacity in the control area is expect to increase to over 18,000 MW by 2017 with a substantial portion of the increase accounted for by the development of offshore wind resources (Vattenfall, 2010).

As system operator, 50Hertz is responsible for accepting and transmitting all fed-in energy in compliance with the German Renewable Energy Sources Act (EEG). 50Hertz also has the obligation of maintaining a balance between power generation and demand within its control area. It traditionally meets this goal through the deployment of balancing energy. There are three categories of balancing (or control) power: primary, secondary, and tertiary control. In general, these forms of control power are non-locational in nature and thus are less than ideal in managing transmission congestion within the control area. This can be an important issue with respect to wind energy because the wind farms in 50Hertz tend to be located in the northern portion of the control area while the major load centers are further south. Investments have been made in upgrading the transmission system but the growth in transmission capacity has lagged the growth in wind energy capacity. As a result, there are occasions when there is more wind energy than the transmission system can accommodate. For this reason, 50Hertz also takes actions under S.13.1 and S.13.2 of the German Energy Industry Act (EnWG). These actions are justified as necessary to ensure “safe, secure, and reliable operations.” They include the re-dispatch of generating units, the modification of power feed-ins, electricity transits, and electricity off-takes from the transmission system.
These interventions can be location specific and thus provide the system operator with the ability to manage transmission congestion within the control area. Details of one such intervention on 25-26 December 2009 are documented in “Report of the Management System of Measures and Adjustments under Energy Act § 13, during the Period of Strong Winds in the period 25/12/2009 to 26/12/2009” (50Hertz, 2009). During the course of this event, the actual level of wind energy at one point was more than 1,800 MW higher than forecasted and actually exceeded the level of electricity consumption in the entire control area by over 750 MW. To accommodate the oversupply of wind energy, significant levels of both secondary control power and minute reserves were dispatched down. For example, at one point during hour 19 on 25 December 2009, a total of almost 1,100 MW of secondary and minute reserves were dispatched downward. During this same hour 2,290 MW of EnWG actions were implemented. Consistent with the aforementioned report, 50Hertz’s discussion of its EnWG actions is couched in terms of the challenge of ensuring the stability of the power grid when the share of electricity consumption accounted for by wind energy is high. 50Hertz’s 2009 annual report is remarkably candid on this point:

“The installed capacity of wind power generation in the 50Hertz Transmission control area had reached approximately 10,500 megawatts (MW) at year-end 2009. The installed wind power capacity had therefore risen 820 MW, or 8.5 %, on the previous year by the end of December 2009. Against this backdrop, the principal challenge was to control the fluctuations in considerably increased wind power feeding such as to consistently guarantee system security. The maximum reached in terms of simultaneous feeding from wind power plants in the 50Hertz Transmission control area during the financial year was 9,081 MW on 18 November 2009. To guarantee safe and secure system operation in the control area of 50Hertz Transmission, network- and market-related measures according to section 13, subsection 1 EnWG had to be resorted to ever more frequently. Ranging even to the point of re-dispatch and adjustments according to section 13, subsection 2 EnWG, these measures were necessitated by the growing discrepancy between the high installed wind generation capacity (approx. 41 % of capacity installed in Germany) and the relatively low electricity consumption (approx. 20 % of all-German consumption). Network extension projects have failed to keep pace with this development.” (50Hertz, 2010, p 10)
Before proceeding, we note that the system frequency of a power system describes the balance between electricity production and consumption. The better the balance, the smaller the deviation between system frequency and its setpoint value. 50Hertz takes its name from the European system frequency’s setpoint value of 50 Hz (60 Hz in North America). This is the system frequency value that the system operator strives to maintain so as to ensure reliability. This can be a daunting challenge at times. National Grid, the system operator in the United Kingdom has described this challenge as “a bit like trying to keep a car at 50mph while driving up and down hills.”

**Figure 5. The 50Hertz Control Area in Germany**
In this paper, we consider the relative importance of wind energy in inducing 50Hertz to take EnWG actions. Over the period 1 November 2008 – 31 December 2009, EnWG actions were undertaken in about 22 percent of the 15 minute reporting periods. The median action was 1,000 MW. In five percent of the cases, the action by the system operator exceeded 3,180 MW. In one percent of the market periods, the action by the system operator exceeded 4,155 MW.

In section 5, EnWG actions by 50Hertz are modeled as a binary variable whose value equals one if an action occurs and equals zero otherwise.\(^6\)

The incidence of the reliability actions is hypothesized to be a function of forecasted load, the share of forecasted electricity demand accounted for by wind energy, the error in the load forecasts, and the errors in the wind energy forecasts. The model distinguishes between positive and negative forecasting errors. The estimation was conducted using the binomial complementary log-log model, a nonlinear specification commonly used in examining the contribution of variables that influence the probability of an uncommon binary event. Algebraically, the model is given by:

\[
\ln(-\ln(1 - p_t)) = c + \alpha_1 FDEMAND_t + \alpha_2 FWindshr_t + \alpha_3 NegDemandError_t + \alpha_4 PosDemandError_t + \alpha_5 NegWindError_t + \alpha_6 PosWindError_t
\]

where \(p_t\) is the probability that the system operator will respond to a reliability challenge in reporting period \(t\). The transformation on the left-hand side of (1), the complementary log-log, takes a number that is restricted to the (0, 1) interval and converts it into a value that has no upper or lower bound (Allison, 1999, p. 3.10). Consequently, the estimated equation is

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\(^6\) Analysis of the magnitudes of the actions is deferred for future work. We also do not currently distinguish between actions undertaken under S.13.1 of the legislation as opposed to S.13.2.
nonlinear, with the marginal impact of any single independent variable contingent on the values of the others.

The variables on the right hand side of equation (1) are defined as follows:

- $FDemand_t$ is the forecasted level of electricity demand for period $t$;
- $FWindShr_t$ is the share of forecasted demand in period $t$ accounted for by wind energy;
- $NegDemandError_t$ equals the absolute value of the difference between the forecasted and actual level of demand when the forecasted level of demand is less than actual. It is zero otherwise;
- $PosDemandError_t$ equals the absolute value of the difference between the forecasted and actual level of demand when the forecasted level of demand is greater than actual and zero otherwise;
- $NegWindError_t$ equals the absolute value of the difference between the forecasted and actual level of wind energy in period $t$ when the forecasted level of wind energy is less than actual and zero otherwise;
- $PosWindError_t$ equals the absolute value of the difference between the forecasted and actual level of wind energy in period $t$ when the forecasted level of wind energy generation is greater than actual wind energy and zero otherwise.

4. Wind Reliability in the 50Hertz Transmission System

Among wind energy proponents and advocates, there seems to be a consensus that 1) the uncertainty in wind forecasting is not necessarily greater than the uncertainty in forecasting load and 2) the many advances in forecasting wind in Europe over the past decade make it possible to achieve high levels of wind integration with little or no effort. Such views have been explicitly expressed by the North American Electricity Reliability Corporation
(NERC), whose mission it is to ensure the reliability of the high voltage power system in North America. In NERC’s own words:

“…variable generation resources have a certain amount of inherent uncertainty. However, in many areas where wind power has not reached high penetration levels, uncertainty associated with the wind power has normally been less than that of demand uncertainty. Operating experience has shown that as the amount of wind power increases (i.e., greater than 5% of installed capacity) there is not a proportional increase in overall uncertainty. Consequently, power system operators have been able to accommodate current levels of wind plant integration and the associated uncertainty with little or no effort.

Forecasting the output of variable generation is critical to bulk power system reliability in order to ensure that adequate resources are available for ancillary services and ramping requirements. The field of wind plant output forecasting has made significant progress in the past 10 years. The progress has been greatest in Europe, which has seen a much more rapid development of wind power than North America.” (NERC, 2009, p. 54)

Results reported by Cali et. al. (2006) seem to be consistent with NERC’s assessment. According to their analyses, the root-mean-squared-errors (RMSE) of the day-ahead wind energy forecasts at one of the German TSOs (unidentified) have declined from approximately 10 percent of installed wind capacity in 2001 to approximately six percent of installed wind energy capacity in 2006. Other researchers including Krauss et. al (2006) and Lange et. al. (2006, 2009) have also reported that the RMSEs weighted by capacity are modest. The finding has been cited by the European Wind Energy Association (2007) as evidence that wind power is a reliable source of electricity supply. In an Institute of Electrical and Electronics Engineers (IEEE) publication entitled, “Wind Power Myths Debunked,” Milligan, et. al (2009), drawing on research from Germany, argue that it is a myth that wind energy is difficult to forecast. In their words:

In other research conducted in Germany, typical wind forecast errors for a single wind project are 10% to 15% root mean-squared error (RMSE) of **installed wind capacity** (emphasis added) but drop to 6% to 8% for day-ahead wind forecasts for a single control area and to 5% to 7% for day-ahead wind forecasts for all of Germany.” (Milligan et. al. 2009, p. 93)
We are receptive to the proposition that there have been advances in wind energy forecasting. We are puzzled, however, why any researcher would weight the RMSEs by installed wind energy capacity. In our judgment, it would be far more appropriate to weight the errors by the mean level of either forecasted or actual wind energy production. A wind forecast error weighted by capacity can decline over time, creating an impression that forecast accuracy is improving, even when the error relative to the mean level of actual wind energy production is not declining. To see this, suppose that the wind energy’s capacity factor, defined as the ratio of mean wind energy to installed capacity, declines over time as wind turbines are installed in more marginal locations. In this case, the forecast error relative to the mean level of wind energy may remain constant but the error relative to installed wind energy capacity would decline since installed capacity in this case is increasing at a faster rate than actual production. We should also note here that load forecast errors are never weighted by the capacity of the equipment that consumes electricity. If they were, then load forecast errors would appear to be trivial when in fact they are not. In short, there appears to be no legitimate reason for weighting wind forecast errors by installed wind energy capacity.

While wind forecast errors weighted by wind energy capacity may appear small, there were several instances in November 2009 where the error in 50Hertz’s day-ahead wind forecast was well over 1000 MW (Figure 6). A histogram of the day-ahead wind energy forecast errors for the period 1 November 2008 – 31 December 2009 also indicates that the forecast errors can be quite large (Figure 7). For one percent of the 15 minute reporting periods, the actual wind energy produced was greater than the forecasted level by approximately 1860 MW; for another one percent of the observations, the actual wind energy produced was less than the forecasted level by approximately 1,475 MW. The RMSE of the wind forecasts over this period equals approximately 624 MW which works out to be approximately 34 percent of the average level of wind production. This relative measure of
the wind forecast errors is approximately equal in magnitude to the wind forecasting errors by Amprion (http://www.amprion.net/en/) and TenneT (http://www.tennetso.de/pages/tennettso_de/index.htm), two of the other three electricity control areas in Germany. It is also considerably larger than the errors in forecasting load (Table 1). These errors may have little, if any, impact on operations to the extent that the system operator receives and acts upon any revised forecasts. However, evidence from the ERCOT power grid in Texas shows that the errors in wind forecasting are highly correlated across hours, i.e. the errors in the hour-ahead forecasts are highly correlated with the errors in the previous day-ahead forecasts (Forbes, Stampini, and Zampelli, 2010). This suggests that the day-ahead forecasts errors in 50Hertz may be an adequate proxy for any revised forecasts.

Before proceeding, we should admit that there is some legitimacy to the claim of significant advances in forecasting wind energy. As recently as 2005, the RMSE of wind forecasting errors in 50Hertz were approximately 50 percent of mean wind energy production. However, despite the decline to 34 percent by 2009, the RMSE in MW was actually larger in 2009 than in 2005 (610 MW in 2009 as compared to 564 MW in 2005) because of a 57 percent increase in wind energy production between 2005 and 2009.
Figure 6. Forecasted and Actual Wind Energy Production Levels in 50Hertz, November 1 - 30, 2009
Figure 7. A Histogram of the Day-Ahead Wind Forecasting Errors in the 50Hertz Power Grid in Germany, 1 November 2008 – 31 December 2009

Table 1 - Day-Ahead Forecasting Errors in 50Hertz, 1 November 2008 – 31 December 2009

<table>
<thead>
<tr>
<th></th>
<th>Root Mean Squared Error in the Day-Ahead Forecast</th>
<th>Root Mean Squared Error of the Forecast as a Percent of the Mean Level of Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Forecasting</td>
<td>1190 MW</td>
<td>11.0 %</td>
</tr>
<tr>
<td>Wind Energy Forecasting</td>
<td>624 MW</td>
<td>34.2 %</td>
</tr>
</tbody>
</table>

Based on 40,601 observations

5. Estimation and Results

Results of the multivariate analysis of the likelihood of EnWG actions by 50Hertz are reported in Table 2. The coefficient on the variable $FDemand$ is negative indicating that the probability of an EnWG action is lower, the higher the level of forecasted demand. The
coefficient on $FWindShr$ is positive and highly statistically significant indicating that the probability of an EnWG action is higher, the higher the level of forecasted demand accounted for by wind energy. The coefficient on $PosDemandError$ is negative and statistically significant. One explanation for this result is that the transmission system is less congested than expected when forecasted demand is greater than actual. Consistent with this view, the coefficient on $NegDemandError$ is positive and statistically significant indicating that EnWG actions are more likely when forecasted demand is less than actual demand. This is consistent with expectations since the distribution network is more likely to be congested when actual demand exceeds the forecasts. The coefficient on $PosWindError$ is negative and highly statistically significant indicating that EnWG actions are less likely whenever the forecasted level of wind energy exceeds actual wind energy production. This is consistent with what one would expect since a shortfall of wind energy reduces any wind energy induced transmission congestion within 50Hertz, making EnWG actions less necessary. The shortfall itself can be resolved by the traditional balancing instruments, the upward dispatch of primary, secondary, and tertiary control power. The coefficient on $NegWindError$ is positive and highly statistically significant indicating the EnWG actions are more likely whenever the forecasted level of wind energy is less than actual wind energy production. Again, this is consistent with our expectations since forecasted wind energy being less than actual means that there is more wind energy than the transmission system can safely accommodate and the system operator responds by implementing EnWG actions. We suspect the balancing market is also impacted but defer our analysis of this for future work.
Table 2. - Results for EnWG Actions

<table>
<thead>
<tr>
<th>Variable</th>
<th>Estimated Coefficient</th>
<th>T-Statistic</th>
<th>P-Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>C</td>
<td>-6.3545</td>
<td>54.8</td>
<td>~ 0</td>
</tr>
<tr>
<td>FDemand</td>
<td>0.0002</td>
<td>17.4</td>
<td>~ 0</td>
</tr>
<tr>
<td>FWindShr</td>
<td>10.0881</td>
<td>85.0</td>
<td>~ 0</td>
</tr>
<tr>
<td>PosDemandError</td>
<td>-0.7459</td>
<td>5.5</td>
<td>~ 0</td>
</tr>
<tr>
<td>NegDemandError</td>
<td>4.7995</td>
<td>22.0</td>
<td>~ 0</td>
</tr>
<tr>
<td>PosWindError</td>
<td>-0.0002</td>
<td>5.4</td>
<td>~ 0</td>
</tr>
<tr>
<td>NegWindError</td>
<td>0.0009</td>
<td>29.6</td>
<td>~ 0</td>
</tr>
<tr>
<td>Number of observations</td>
<td>40,594</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number of Nonzero Observations</td>
<td>8,912</td>
<td></td>
<td></td>
</tr>
<tr>
<td>McFadden's R2:</td>
<td>0.508</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The reported t-statistics are robust to Heteroskedasticity

We use the estimated coefficients to simulate the probabilities of EnWG actions in the basecase scenario (with variables at their observed values) and in the counterfactual of zero forecasted wind share and zero wind forecasting errors (with all of the other variables held equal to their actual values). The average predicted probability is 0.2164 while the average counterfactual probability is 0.0147. The difference between these two probabilities represents the magnitude of wind’s energy challenge to reliability, i.e. on average wind energy raises the probability of an EnWG event by a factor of about 15.

Figure 8 depicts the wind related incremental probabilities for 25 large EnWG events. For each of these events, the model’s predicted probability of the event occurring was equal to 1.00. The predicted wind related incremental probability, the height of the bars for each of the EnWG events, is the portion of the predicted probability that the model attributes to wind energy. Note that for all of these events this incremental portion due to the presence of wind power is estimated to be over 90 percent. The EnWG actions on 25-26 December 2009 that were noted earlier are also correctly predicted by the model. For example, EnWG actions in hour 19 on 25 December 2009 were 2290 MW in magnitude. The model predicted probability of these actions occurring is 1.00. The predicted wind related incremental probability during each of the 15 minute intervals during this hour is approximately 0.988.
Figure 8 - Predicted Wind Related Incremental Probabilities for 25 Large EnWG Events

Note: In each case in the above figure, an EnWG event occurred and the calculated probability of an EnWG event occurring is equal to 1.00. The predicted wind related incremental probability is the portion of the predicted probability that the model attributes to wind energy.

6. Conclusions

In this paper, we use a standard economic model to show that increasing supplies of wind energy through subsidies and/or tax credits alone does not adequately respond to the goal of reducing carbon emissions. Second, we cast substantial doubt on the appropriateness of weighting wind forecasting errors by installed wind energy capacity, and show that when the appropriate normalization is used forecasting errors remain large. Third, we find that the higher the wind energy share of forecasted demand, the more likely it is that a system operator will need to undertake measures to maintain “safe, secure, and reliable operations”. Our estimates indicate that the presence of wind power raises the probability of such
measures by a factor of 15, relative to the counterfactual of absence of wind power. It is worth noting here that some might argue that the problem can be avoided with an expansion of transmission capacity. This is incorrect. Expansion of transmission capacity, though making traditional balancing methods more feasible, does not address the fundamental issue—the large imbalances that occur because wind energy is highly variable and difficult to forecast. Extending the metaphor of the United Kingdom National Grid, it seems that maintaining system reliability in the presence of high wind energy penetration is a bit like trying to keep a car at a constant speed of 50 mph while driving under poor visibility up and down a mountainous road that has sharp turns, some very large potholes, and not much of a guardrail.

In less colorful terms, the results of this paper should serve as a caution to those who argue for government policies directed at the large scale penetration of wind energy into electric power grids. Correspondingly, to justify such policies on the grounds that they are warranted by the dangers to the planet from climate change misses a salient point. There are other more efficient, less costly, and less risky ways of meeting the climate change challenge. The real problem is that they lack popularity.

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Are Policies to Encourage Wind Energy Predicated on a Misleading Statistic?

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Fourteenth Annual Midwest Energy Conference
15 March 2011
Trends in Public Policy

• There is almost no chance that the United States Congress will pass either a carbon tax or cap-and-trade legislation any time soon.

• There is broad political support for increasing substantially the share of electricity generation from wind.

• Some have advocated that policymakers should strive to have 20 percent of generation be accounted for by renewable energy by 2030 with most of the increase accounted for by wind energy.
Keeping the Lights On

• Blackouts have large societal costs.

• The stability of the power grid requires that the supply of power equal demand at all times, not just on average.

• To avoid blackouts, reserve power is dispatched when there is an imbalance between electricity supply and demand.
Reserve Deployments by the Bonneville Power Administration, 2 November - 1 March 2011
Wind Energy and the Power Grid

• Wind energy is not fully dispatchable

• System Operators integrate wind energy into the generation mix by forecasting wind energy production levels
Wind Energy and the Power Grid (cont’d)

The proposed increases in wind energy are implicitly predicated on the belief that wind energy, while not capable of “upward dispatch”, is fairly predictable.

But is it?
The “Consensus” View

1) Forecasting wind energy is critical to system reliability when wind energy penetration is high.

2) The uncertainty in wind forecasting is not necessarily greater than the uncertainty in forecasting load.

3) The many advances in forecasting wind in Europe over the past decade that makes it possible to achieve high levels of wind integration with little or no effort.
NERC’s Views on Wind Energy

“...in many areas where wind power has not reached high penetration levels, uncertainty associated with the wind power has normally been less than that of demand uncertainty. ... Consequently, power system operators have been able to accommodate current levels of wind plant integration and the associated uncertainty with little or no effort.

Forecasting the output of variable generation is critical to bulk power system reliability in order to ensure that adequate resources are available for ancillary services and ramping requirements. The field of wind plant output forecasting has made significant progress in the past 10 years. The progress has been greatest in Europe, which has seen a much more rapid development of wind power than North America.” (NERC, 2009, p. 54)
Evidence of Declining Day-Ahead Wind Energy Forecast Errors

Source: Cali, et. al. (2006)
Is the evidence compelling?

• Though the forecasting error relative to installed wind energy capacity may have declined, is such a metric even relevant?

• Note that load forecasting errors are not weighted by the capacity of the equipment that consumes electricity.
Is the evidence compelling? (cont’d)

• An error weighted by the mean level of actual wind energy (or the mean forecasted level) would seem far more relevant.

• Weighting by capacity makes it difficult to compare the accuracy of the wind forecasts with the accuracy of the load forecasts.

• Weighting by capacity makes it difficult to compare the accuracy of the wind forecasts by one system operator with another since capacity utilization varies across systems. Ignoring this reality makes systems with low wind energy utilization “look” more accurate even if they are not.

• A capacity-weighted error can decline over time even if the unweighted error is not declining.

• There seems to be no legitimate reason to weight errors by capacity.
Measuring Forecast Errors

• Wind forecasting errors will be measured as the root-mean-squared-error of wind forecasts relative to mean wind energy production.

• Load forecasting errors will be measured as the root-mean-squared-error of load forecasts relative to the mean electricity load.
The Root-Mean-Squared-Error (RMSE)

\[ RMSE = \sqrt{\frac{\sum(Forecasted - Actual)^2}{n}} \]
Electricity Control Areas Examined

- Western Denmark
- Eastern Denmark
- 50Hertz in Eastern Germany
- TenneT in Central Germany
- Amprion in Western Germany
- Italy
Electricity Control Areas Examined (cont’d)

- United Kingdom
- Ireland
- ERCOT (USA)
- The Midwest ISO (USA)
- Bonneville Power Administration (USA)
Wind Energy Production Relative to Load in Western and Eastern Denmark, 14 September 2009 – 31 December 2010

The chart illustrates the proportion of wind energy production relative to load for Western and Eastern Denmark. Western Denmark had significantly higher wind energy production as a percent of load compared to Eastern Denmark during the specified period.
Forecast Errors in Western Denmark
14 September 2009 – 31 December 2010

![Bar chart showing RMSE of the forecast as a percent of the mean level of activity for Wind and Load. The RMSE for Wind is significantly higher than for Load.](chart.png)
Forecast Errors in Eastern Denmark
14 September 2009 – 31 December 2010

RMSE of the Forecast as a Percent of the Mean Level of Activity

- Wind: 60%
- Load: 0%

Wind Load
Electricity Control Areas in Germany

- 50Hertz
- TenneT
- EnBW
- Amprion
Day-Ahead Wind Forecast Errors in 50Hertz, 2005-2010

RMSE of the Wind Forecasts as a Percent of the Mean Level of Wind Energy Production

- 2005
- 2006
- 2007
- 2008
- 2009
- 2010
Forecasting Errors in 50Hertz
1 May 2008 – 30 November 2010

The graph shows the root mean square error (RMSE) of the forecast as a percent of the mean level for different categories:

- Wind
- Total Generation
- Load

The RMSE for Wind is significantly higher than for Total Generation and Load.
Day-Ahead Wind Forecast Errors in TenneT in Central Germany, 2006-2010

RMSE of the Wind Forecasts as a Percent of the Mean Level of Wind Energy Production

- 2006
- 2007
- 2008
- 2009
- 2010
Forecast Errors in Amprion
1 April 2008 – 15 December 2010

RMSE of the Forecast as a Percent of the Mean Level

- Wind
- Total Generation
- Load
Forecast Errors in Italy
1 March – 31 December 2010

RMSE of the Forecast as a Percent of the Mean Level

- Wind: 25%
- Load: 2%

Forecast as a Percent of the Mean Level
Forecast Errors in the UK Power Grid
5 November 2008 – 9 October 2010

Note: Wind forecasts based on 30 minute data; load forecasts based on hourly data.
Wind Forecasting Errors in Ireland
2 February 2010 – 31 December 2010

![Bar Graph](image)
Forecasting Wind Energy in ERCOT

• ERCOT is the system operator that serves the vast proportion of Texas.

• Over the period 5 December 2009 – 30 November 2010, wind energy accounted for approximately 7.4 percent of load.

• Porter and Rogers (2010, p. 5) report that the mean absolute wind forecasting errors in ERCOT ranged from 8.28% to 10.73% of capacity for all hours over the May 2009-August 2009 period.
The ERCOT Control Area
Forecast Errors in ERCOT
5 December 2009 – 30 November 2010

The figure shows the Root Mean Square Error (RMSE) of forecasts as a percent of the mean level. The RMSE values are as follows:

- Day Ahead Hour 12 Wind Forecast: 45%
- Hour Ahead Wind Forecast: 40%
- Day Ahead Hour 12 Load Forecast: 5%
The Midwest ISO
The MidWest ISO’s Assessment of Wind Forecast Accuracy

“The Midwest ISO’s wind forecasting accuracy for 2009 was 92.83%. (emphasis added) Wind forecasting accuracy data prior to 2009 is not available. Wind forecasting accuracy is calculated using an industry-wide methodology called Mean Absolute Error (MAE). The MAE is the average of the absolute value of the difference between forecasted and actual wind power output and is expressed as a percent of installed wind nameplate capacity. The wind forecasting accuracy is represented as one minus MAE.

The wind forecasting calculation methodology differs from the calculation methodology used for the load forecasting accuracy metric because the wind forecasting calculation methodology expresses the absolute error value as a percent of installed wind nameplate capacity whereas the load forecasting calculation methodology expresses the absolute error value as a percent of total forecasted load. The wind forecasting calculation methodology “softens “ the true error in forecasting. (emphasis added)

The Midwest ISO is continuing to explore methods for improving the accuracy of its wind forecasting, but our current accuracy appears to be consistent with the accuracy obtained in other regions throughout the world(emphasis added).“

RTO/ISO Performance Metrics, AD10-5-000, 2010, p 151
Day-Ahead Forecast Errors in the Midwest ISO June 15 – 31 December 2010

- Mean Level of the Forecast as a Percent of the Mean Level:
  - Wind: 25%
  - Load: 5%

RMSE of the Forecast as a Percent of the Mean Level
The Bonneville Power Administration

BPA is the balancing authority responsible for maintaining a constant balance between the power load and power generation in the area shown in teal. (A balancing authority is also known as a control area.) Most of the wind power on line and planned for the Pacific Northwest is clustered in BPA’s balancing authority at the eastern end of the Columbia River Gorge. However, 50 percent of the wind power in BPA’s balancing authority area serves loads in other utilities’ balancing authorities.
Projected Growth in Wind Energy in the BPA Control Area

Projected Wind Projects Connected to BPA Grid on Existing Queue and Recent Trends

Northwest wind power is growing fast.

We’re at 2,780 MW.
A Rorschach Test:
Forecasted vs. Actual Wind Energy for the BPA Control Areas, November 1-30, 2010
The Wind Forecast Errors for BPA November 1-30, 2010

• The RMSE of the wind forecast for November 2010 (see previous slide) was 24 percent of the average level of wind energy production.

• The largest positive error was 898 MW.

• The largest negative error (in absolute value) was -1084 MW.
Monthly Capacity-Weighted Wind Forecast Errors for BPA, May 2008 – December 2010
Wind Forecast Errors for BPA Weighted by Mean Monthly Wind Energy, May 2008 – December 2010
Wind Forecast Errors and the Deployment of Reserve Power by BPA: 2 Nov 2010 - 1 March 2011
The Potential Consequences of Large-Scale Wind Energy Penetration for System Operator Uncertainty

- Assume two sources of forecasting error, load and wind.
- Total system error is equal to the sum of unexpected load (ULOAD) and unexpected wind (UWIND).
- Total uncertainty is equal to the variance of (ULOAD + UWIND).
Total Uncertainty per MWH of System Load:  
A Function of Wind Penetration

\[
\text{var}(ULOAD + UWIND) = \text{var}(ULOAD) + \text{var}(UWIND) + 2 \text{cov}(ULOAD, UWIND)
\]

Multiply and divide var(UWIND) by mean wind production (MEANWIND). Then divide both sides by average load (MEANLOAD) to derive uncertainty per MWH of load.

\[
\frac{\text{var}(ULOAD + UWIND)}{\text{MEANLOAD}} = \frac{\text{var}(ULOAD)}{\text{MEANLOAD}} + WINDSHARE \left( \frac{\text{var}(UWIND)}{\text{MEANWIND}} \right) + 2 \left( \frac{\text{cov}(ULOAD, UWIND)}{\text{MEANLOAD}} \right)
\]

where \( WINDSHARE = \frac{\text{MEANWIND}}{\text{MEANLOAD}} \) and measures the degree of wind penetration.

Using data from control areas on actual and forecasted load and wind energy, the uncertainty impact of increased wind energy penetration on system operators can be estimated.
Total Uncertainty per MWH of System Load: A Function of Wind Penetration: The Case of Western Denmark

• Wind Energy is currently equivalent to about 30 percent of load in Western Denmark

• The Government of Denmark wants to achieve 50% wind integration by 2025.

• Based on the variance of ULOAD and UWIND and their covariance for Western Denmark, achieving the goal of 50% wind would increase the uncertainty per MWh by about 57%
Total Uncertainty per MWH of System Load: A Function of Wind Penetration: The Case of the Midwest ISO

• Wind Energy is currently equivalent to about 3.4 percent of load in the Midwest ISO

• The American Wind Energy Association is promoting legislation that would achieve 20% wind integration by 2030.

• Based on the variance of ULOAD and UWIND and their covariance for the Midwest ISO, achieving the goal of 20% wind would increase the uncertainty per MWh by about 62%
Conclusions

• There is no legitimate reason to weight wind forecast errors by installed wind energy capacity

• The errors in forecasting wind energy are much larger than the errors in forecasting load.

• The data from the BPA makes it clear that the errors have consequences for power grid operations.

• Increases in wind energy penetration increase the operating uncertainty that system operators must confront to keep the lights on.

• Wind energy policies should reflect these realities.
NOTES
BIOGRAPHIES
Martin J. Bregman Bio

Marty has been involved in a wide variety of utility regulatory matters since 1981 when he became an Assistant Public Counsel in the state of Missouri. In 1983, Marty was hired as regulatory counsel by The Gas Service Company which was acquired later that year by The Kansas Power and Light Company (KPL). KPL acquired Kansas Gas and Electric Company in 1992 and sold its natural gas operations in 2003 and changed its name to Western Resources, Inc. and later Westar Energy, Inc.

As Executive Director, Law for Westar, Marty acts as lead counsel in all major regulatory matters in Kansas and participates actively in matters at the Federal Energy Regulatory Commission. As counsel for Westar, Marty has also argued appeals in the D.C. Circuit Court of Appeals, the Tenth Circuit Court of Appeals and the appellate courts of Kansas and Missouri. Marty also oversees litigation related to Westar’s utility operations.

Marty graduated from the Massachusetts Institute of Technology in 1972 with a B.S. in Political Science and received his J.D. from Boston University in 1975. He resides in Lawrence with his wife, Nancy, and their little dog, Tess.
Prior to joining PJM, Mr. Duane was vice president & general counsel for the North American and Caribbean businesses at Mirant Corp. He previously served as vice president, secretary & general counsel at Southern Company Energy Marketing. Mr. Duane began his career in private practice in Washington, D.C., where he represented public power and industrial consumer interests.

Mr. Duane is a member of the American Corporate Counsel Association, Energy Bar Association and the Maryland State Bar Association.

Mr. Duane earned a bachelor of arts in Political Science from McGill University, a juris doctor with honors from University of Maryland School of Law and a master of science with honors from Georgetown University, School of Foreign Service.

PJM Interconnection ensures the reliability of the high-voltage electric power system serving 51 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region’s transmission grid, which includes 6,038 substations and 56,250 miles of transmission lines; administers the world’s largest competitive wholesale electricity market; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion.
Kevin F. Forbes

Kevin Forbes received his Ph.D. from the University of Maryland and is currently an associate professor of economics at The Catholic University of America. He has extensive experience providing econometric modeling support to both Natural Resources Canada and the United States Department of Energy.

His research interests include oil and natural gas supply and price issues, the performance of electricity markets, the integration of wind energy and PV solar power into the power grid, the contribution of wind energy to lower carbon emissions, and the performance of carbon markets. He is also researching the impact of geomagnetic storms on power grid operations and real-time electricity markets. This research is currently being supported by the National Science Foundation. A spinoff of this research has recently induced him to seek the counsel of a patent lawyer. A patent application is expected to be filed in April.
Bob Heidorn has a BA in English Literature and History from Miami University where he was elected to Phi Beta Kappa. Upon graduation from University of Wisconsin Law School (cum laude) in 1988, Mr. Heidorn joined the Indianapolis law firm of Barnes & Thornburg. He practiced in the firm’s creditors’ rights and public utilities departments until 1995 when he joined Indiana Energy, Inc. as Corporate Counsel. In 2000, Mr. Heidorn became Vice President, Deputy General Counsel for Vectren Corporation, and in 2010 was promoted to General Counsel, Chief Compliance Officer of the company. He resides in Evansville with his wife and son, and is President of the Carver Community Organization.
Stephen G. Kozey
Vice President,
General Counsel and Secretary

Stephen G. Kozey is Vice President, General Counsel and Secretary for the Midwest Independent Transmission System Operator, Inc., a position he has held since 2000.

Mr. Kozey’s 30+-year career has focused on the electric industry -- rate and regulatory matters, Federal Energy Regulatory Commission jurisdictional matters, power and commodities trading functions, as well as industry mergers and acquisitions and antitrust litigation. During his career Mr. Kozey held various legal positions with electric utilities (PSI Energy and its successor Cinergy, which he left as General Counsel of Cinergy’s Energy Commodities Business Unit ‘92-’00), Associate General Counsel at Potomac Electric Power Company ‘84–’87), private law firms in the District of Columbia (Skadden, Arps, Slate, Meagher & Flom, ’88-’92; Reid & Priest ’80-’84, and Dickstein, Shapiro & Morin ’76-78) and a state regulatory agency (Public Staff of the North Carolina Utilities Commission ’78-‘80).

Mr. Kozey earned his J.D. degree in 1976 from the Law School of the University of Pennsylvania in Philadelphia. He graduated Magna Cum Laude from Haverford College in Haverford, Pa., where he was elected to Phi Beta Kappa and received a Bachelor of Arts Degree in religion and political science. He is a member of the bar in the District of Columbia, North Carolina, Maryland and Indiana.
Michael A. Laros
Partner, Global Energy Practice

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Mobile: +1 812 360 8988

Mike has over thirty-five years of utility industry management consulting experience with particular expertise in the areas of major-project cost effectiveness, fuel and power procurement, utility restructuring, and organizational development. He has directed industry restructuring-related assignments for utility and regulatory clients in the U.S, England, Canada, and South Africa. Mr. Laros has testified as an expert regarding the reasonableness of utility management practices in a variety of civil litigation matters and in rate proceedings before the Federal Energy Regulatory Commission (FERC), and the California, Illinois, New Jersey, Ohio and Texas state public utility commissions.

Primary expertise

• Complex Project Planning and Oversight – Assists management in planning and implementing effective project management and oversight of large complex projects
• Performance Benchmarking – Comparative analysis of management efficiency and effectiveness applied to problem identification and resolution
• Litigation Support – Expert analysis and testimony pertaining to management performance, identification of causes of liability, and quantification of damages in complex regulatory and civil litigation matters
PROFESSIONAL AFFILIATIONS AND PUBLICATIONS

Member  Project Management Institute

Member – American Nuclear Society

Member – Midwest Energy Bar Association Board of Directors

Past Member, Keystone National Policy Dialogue on Commercial Nuclear Reactor Decommissioning, Washington DC.

Publications:


Demand-side Management: Surviving in the '90s, Public Utilities Fortnightly, co-authored with Brian J. Daley, August 1, 1992.


Prudence Revisited, Electric Light & Power, August, 2007
Commissioner Valerie A. Lemmie
Term ends: April 10, 2011

Commissioner Valerie A. Lemmie was appointed to the Public Utilities Commission of Ohio (PUCO) by Governor Bob Taft in 2006 and reappointed by Governor Ted Strickland in 2007. Ms. Lemmie is active in state regulatory organizations, including serving as president of the Organization of MISO States (OMS), a Board Director of the National Regulatory Research Institute (NRRI), a member of the ABACCUS (Annual Baseline Assessment of Choice in Canada and the United States) Advisory Committee and a member of the Financial Research Institute Advisory Board at the University of Missouri, her alma mater. She is also immediate past president of the National Academy of Public Administration (NAPA) where she is a NAPA Fellow.

Prior to her appointment as Commissioner, Ms. Lemmie had a distinguished career in local government serving as city manager for the cities of Petersburg, Virginia, Dayton and Cincinnati Ohio. Early in her public service career, Ms. Lemmie was the deputy director of the D.C. Department of Consumer and Regulatory Affairs where she was responsible for the oversight of state regulatory functions, including land use and zoning, facility citing and permitting, and environmental standards and protection. She was later appointed Arlington County, Virginia’s first Director of Environmental Services.

Over the course of her local government career, Ms. Lemmie has directed and provided oversight of municipal utilities, including water and sewer services, a major waste-to-energy facility and landfills with methane gas recovery sold to the energy grid. She also served as the local government representative on President Clinton’s Greenhouse Gas Advisory Committee and more recently as the local government member of House Speaker Dennis Hastert’s Committee on Urban Redevelopment.

Ms. Lemmie has been an adjunct professor at both Howard University and the University of Dayton, teaching courses in consumer affairs and public administration. She has also been a Fellow at the Center for Excellence in Municipal Management at George Washington University and a scholar-in-residence at the Kettering Foundation.

A published author and speaker on public policy and state regulatory issues nationally and internationally, Ms. Lemmie earned a bachelor’s degree in Political Science and Urban Sociology from the University of Missouri and a master’s degree in Urban Affairs/Public Policy Planning from Washington University. She has completed post graduate work in economics at Virginia State University and executive leadership programs at Harvard University and the University of Virginia.

Sample Introduction
Commissioner Valerie A. Lemmie was appointed to the PUCO by Gov. Bob Taft in 2006 and reappointed by Gov. Ted Strickland in 2007. Commissioner Lemmie has extensive experience in the public sector, working as city manager for the cities of Cincinnati, Dayton, and Petersburg, Va. With the city of Cincinnati, Lemmie was responsible for overseeing 15 city departments with more than 6,000 employees and a $1 billion budget. Most recently, she served as a scholar-in-residence at the Kettering Foundation, a research organization focused on democracy and the strengthening of public life. Commissioner Lemmie earned a bachelor’s degree in Political Science and Urban Sociology from the University of Missouri and a master’s degree in Urban Affairs/Public Policy Planning from Washington University.
Monica Martinez, Commissioner

Monica Martinez was appointed by Governor Jennifer M. Granholm to the Michigan Public Service Commission on July 3, 2005. Her term ends July 2, 2011.

Since joining the Commission, Commissioner Martinez has led new Commission consumer education and awareness efforts promoting low-income and senior programs, energy affordability via efficiency, and the value of generation resource diversity. Commissioner Martinez has taken an active role in promoting energy efficiency and renewable energy development in the state, playing a key role in the development of the state RPS and energy efficiency laws as well as their implementation. Governor Granholm appointed her to the Climate Action Council, where she oversaw policy direction related to carbon reduction solutions across all industries. As a result of her dedicated and passionate role in shaping Michigan's future energy policy, she was named Leader of the Year for 2009 by the Great Lakes Renewable Energy Association.

Recognized for her national leadership, Commissioner Martinez is the immediate past President of the Mid America Regulatory Conference and serves on various panels and tasks forces focusing on economic development, regional markets, at-risk customers, and services for the hearing impaired. In October 2009 she was elected as Vice President of the Organization of MISO States (OMS) and will serve as the lead state representative before the Midwest ISO (MISO) board of directors at the MISO Advisory Committee. She is also a member of the National Association of Regulatory Utility Commissioners (NARUC) and serves on the Consumer Affairs and the Telecommunications Committees.

Prior to her appointment to the Commission, Ms. Martinez served as the Governor's Deputy Director for Legislative Affairs, where she served as a key liaison to the Michigan Legislature and advised the Executive Office on policy and governmental relations. Her career also includes positions at the Michigan Senate Democratic Office as a senior policy advisor where she specialized in telecommunications, energy, human services, and family law policy issues and at the Alumni Association of the University of Michigan and U of M Dearborn's Center for Corporate and Professional Development.

Dedicated to community and public service, she serves as a liturgical minister at her church and provides pro-bono consulting services in strategic planning, marketing, and fundraising to non-profit charities.

Commissioner Martinez earned a Bachelor's degree, majoring in Economics and Political Science and a Master's in Business Administration, with distinction, both from the University of Michigan.
Indiana Utility Consumer Counselor David Stippler

David Stippler became the 23rd Utility Consumer Counselor for the State of Indiana on March 10, 2008. Having specialized in public utility law throughout most of his career, David brings 35 years of experience as a practicing Indiana attorney to his role as the State’s Utility Consumer Counselor.

David oversees a dedicated staff of over 50 utility professionals who represent Indiana’s residential, commercial and industrial ratepayers in state and federal utility regulatory proceedings.

Before joining the OUCC, David practiced law with the Indianapolis law firm of Bingham McHale, LLP where he represented utilities and municipalities on a wide range of legal and regulatory issues affecting their business activities. He also served for many years as in-house counsel with Ameritech Corporation and SBC Communications. Before his corporate law experience, David was engaged in private practice, concentrating in corporate law and civil litigation in Indianapolis.

An Evansville native, David is a 1973 cum laude graduate of the Indiana University School of Law – Indianapolis. He is also an alumnus of Saint Meinrad College and the University of Evansville.

David has served on the Saint Meinrad Alumni Association’s Board of Directors. He is a Director Emeritus and past president of the Lawrence Township School Foundation in Marion County. He has also served on the Board of Trustees of Marian College and the Board of Directors for the Arts Council of Indianapolis.

David and his spouse, Elizabeth, reside in Carmel, Indiana.
As Senior Director of Expansion Planning at the Midwest ISO, Jeff directs the development of regional expansion plans for the 14 state Midwest ISO region. He is the principle architect of the FERC approved cost allocation protocols in place today in the Midwest ISO for reliability and economic expansions. In addition, he directs planning analysis for inter-regional Coordinated System Plans with neighboring planning entities, including the Department of Energy’s EIPC planning initiative.

Prior to the Midwest ISO, Jeff spent over 20 years with Commonwealth Edison Co. in Chicago where he managed Transmission Planning.

Over the past 25 years, Jeff has been an active member on NERC planning related committees involved in establishing and applying national reliability standards. Jeff holds a Master of Science degree in Electric Power Engineering from Rensselaer Polytechnic Institute.
Warren Wood

Warren Wood, a registered professional engineering in Missouri, has over twenty years of experience in utility industry infrastructure design and construction, utility policy analysis, and state regulation.

In late 2010 Mr. Wood left his role as the President of the Missouri Energy Develop Association (MEDA) to become the Vice President of Legislative and Regulatory Affairs for Ameren Missouri. At MEDA Mr. Wood represented Missouri’s investor-owned and municipal electric, natural gas and water utilities on policy issues at the Capitol and at the Missouri Public Service Commission (PSC). In his new role at Ameren Missouri he continues to work closely with stakeholders on legislative and regulatory policy issues in Jefferson City.

Prior to coming to MEDA, Mr. Wood worked more than eight years at the Missouri PSC where he served as Director of the Utility Operations Division, Manager of the Energy Department, and Manager of the Natural Gas Department. Among other responsibilities in these positions, he worked with state regulatory commissioners and staff, legislators, and the public to understand utility and energy trends and development of short- and long-term energy policy. He served as Chairman of the PSC’s Task Forces on Natural Gas Commodity Prices and Long Term Energy Affordability. He also served as Chairman of the NARUC Staff Subcommittee on International Relations and participated in United States Agency for International Development missions to Rwanda, Zambia and Eastern Europe.

Prior to going to the Missouri PSC, he worked for more than ten years as a consulting engineer with Black & Veatch where he worked extensively on the design of coal fired, single and combined cycle combustion turbine, and nuclear power plants; substation structures; pumping stations; and sewage treatment plants.

Mr. Wood graduated with honors from the University of Missouri-Columbia College of Engineering with a Bachelor of Science degree in Civil Engineering in 1987. Warren lives in central Missouri with his wife, Lisa, and their three sons – all Eagle Scouts. He is an avid fisherman, loves traveling, is a leader in 4-H and Boy Scouts, and is learning to like golf.