Estimating the Value of Additional Wind and Transmission Capacity in the Rocky Mountain West

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Motivating Questions – Wind

• Taxation
• Issues of wind and the grid
  – Transmission Location
  – Transmission Capacity
  – Back-up generation potential
• Species/Land-use issues
• Wind diversity
  – Intermittency
  – Spatial diversification
The Model

• Full modeling framework is not complete.
  – Phase 1: Ben Rashford, Natalie Macsalka, Roger Coupal – spatial model of wind energy/sage grouse location.
  – Phase 2: Godby, Coupal and Greg Torell – individual generator dispatch model of the Rocky Mountain Power Area including transmission relationships.
  – Phase 3: (not completed) CGE model of the Rocky Mountain region economy.
The Eventual Model

Economic growth and management pressures on corridor lands

Wind power/transmission demand and location decisions

Power supply and energy demand
Research Goals in this Paper

• Use the dispatch modeling framework to
  – evaluate the stochastic aspects of wind-powered electricity generation
  – evaluate transmission capacity and losses issues
  – explore interaction of wind-power, transmission and other sources of electricity production in an efficient scheduling framework.
Conceptual Framework

• Model incorporates a dispatch model
  – Model based on generation and demand data in the Rocky Mountain Power Area (RMPA) from 2008-2010.

• Simulation of hourly power outcomes to determine
  – Power price outcomes assuming stochastic wind generation
    • Wholesale electricity price variation
    • Transmission capacity and congestion effects
Model

- What is “the grid”?  

Source: NERC, 2011
The RMPA within the North American Grid

Source: North American Electric Reliability Corporation (NERC).
Model

- Model reduces the load centers within the RMPA to three nodes.
Model

• Model reduces the load centers within the RMPA to three nodes.

TOT 3 Transmission corridor
Model

- Transmission system simplified between nodes following actual transmission paths
Model

• Assumptions:
  1. Load for region exogenous and seasonal using actual 2008 data.
  2. Assume five generation types: Coal, Gas, Hydro, Wind, Solar dispatched by generator.
  3. Existing transmission system creates constraints between nodes and power losses.
  4. Power is dispatched within each node to satisfy load minimizing system cost.
Model: Dispatch power necessary at minimum cost

Transmission network with losses

Load Required

\[ P_L \]
Dispatch Model

- Dispatch occurs throughout the day, creating time-dependent system prices.

Source: Hogan (1998)
Model (Simplified)

- Minimize total generation costs $F_T$ given each source generates $P_i$, line losses are $P_l$, total power needed $L$, and given generation and transmission constraints:

$$\text{minimize } F_T = \sum_{i=1}^{n} F(P_i)$$

Subject to

- Energy balance constraint
  $$P = \sum_{i=1}^{n} P_i - P_l = L$$

- Generation constraints
  $$P_{i_{\text{min}}} \leq P_i \leq P_{i_{\text{max}}}$$

- Transmission constraints
  $$|z_i| \leq z_{i_{\text{max}}}$$

- Non-negative generation
  $$P_i \geq 0$$
Model - Generator Cost functions

• Estimate marginal costs by generator deterministically using
  – Reported technology
  – Fuel costs (actual) including transport using reported freight costs
  – Assumed fuel to power efficiency by generation technology using engineering estimates and adjusted for age.
  – operations and maintenance cost estimates reported for similar plants
Figure 6: Generator Vintage by Fuel and Capacity

- **COAL**
- **GAS**
- **PETRO**
- **REN**
- **SOLAR**
- **WATER**
- **WIND**
- **PETRO SB**
- **REN SB**
- **GAS SB**
Simulation

- Actual 2008 demand levels
  - Eventually will simulate demand
- 365 individual generating stations
- Stochastic wind-supply
  - Initially only wind intermittency
  - Later will incorporate stochastic maintenance and other interruptions
  - Utilize a meteorological model to generate random wind outcomes.
- Solve for demand and supply of power to determine price by node given imports/exports and transmission constraints
Wyoming and Colorado Demand, Summer 2008

MW

0
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000
11000
12000

Hour

t5016  t5026  t5036  t5046  t5056  t5066  t5076  t5086  t5096  t5106  t5116  t5126  t5136  t5146  t5156  t5166  t5176  t5186  t5196  t5206  t5216  t5226  t5236  t5246  t5256  t5266  t5276  t5286  t5296  t5306  t5316  t5326  t5336  t5346

Colorado Demand_a2  Wyoming Demand_a1
Wyoming Coal Generation, Summer 2008

Total Sub-coal_a1
Average of Sub-coal_a1
Average of Sub-coal_a2
Wyoming Coal Generation, Summer 2008

MW vs Hour

- Wyoming Demand_a1
- Total Sub-coal_a1
- Average of Sub-coal_a1
- Average of Sub-coal_a2
Wyoming Coal Gen. and Trans. Capacity, Summer 2008

MW

Transmission Capacity

Total Sub-coal_a1

Average of Sub-coal_a1

Average of Sub-coal_a2
Wyoming Coal and Hydro Generation, Summer 2008

Transmission Capacity

Total Sub-coal_a1
Average of Sub-coal_a1
Average of Sub-coal_a2
Average of Hydro_a2
Average of Hydro_a1
Total Hydro
Figure 8: RMPA Estimated Cost Curve by Fuel Type Without Congestion (Summer 2008)
Preliminary Results

• Static framework used to determine effects of sudden increase in wind potential on prices and economic rents
  – Imagine a severe thunderstorm in the height of summer (max. load)
  – Max load occurs in Node 3 (Denver Area)
  – Wind potential suddenly maximized in Node 1 (Wyoming)
  – Impact on prices and economic rents given transmission constraint between Nodes 1 and 3.
Figure 10: Potential Wind Intermittency Impact (No Congestion)
## Preliminary Results

<table>
<thead>
<tr>
<th>Load Scenario</th>
<th>Node</th>
<th>Wind Output Level</th>
<th>Demand (MW)</th>
<th>Efficient Price $/MWh</th>
<th>Efficient Output (MW)</th>
<th>Congested Price $/MWh</th>
<th>Congested Output (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max. RMPA Forecast Load 2008</td>
<td>Node 1</td>
<td>Max.</td>
<td>1506.48</td>
<td>$59.85</td>
<td>2859</td>
<td>$10.89</td>
<td>2736.48</td>
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<tr>
<td></td>
<td></td>
<td>Derated</td>
<td></td>
<td>$77.09</td>
<td>1812.05</td>
<td>$77.09</td>
<td>1812.05</td>
</tr>
<tr>
<td></td>
<td>Nodes 2 &amp; 3</td>
<td>Max.</td>
<td>10778.52</td>
<td>$59.85</td>
<td>9492.8</td>
<td>$66.91</td>
<td>9548.52</td>
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<tr>
<td></td>
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<td>Derated</td>
<td></td>
<td>$77.09</td>
<td>10472.95</td>
<td>$77.09</td>
<td>10472.95</td>
</tr>
</tbody>
</table>

Since transmission constraint between nodes 2 and 3 is not binding – node outcomes combined. Derates to wind: 12% of nameplate capacity.
Preliminary Results

• Sudden increases in wind can overwhelm electricity grid as demand unresponsive to new supply.
  – Can require curtailment of other sources
  – Transmission constraints limit the benefit of new free power
  – Rents: wind producers can actually suffer for the additional wind as electricity price received falls
  – Holders of transmission rights (coal generators) win for sudden increase in their power exported to high priced node even if some power curtailed.
100 MW Transmission increase

• Reduces number of hours congestion occurs
  – 490 fewer fully congested hours (transmission = capacity)
• Reduces price in Colorado, but increases it in Wyoming
  – Colorado average price $29.09/MWh (max $68.94, min $15.30) - reduces price in Colorado by 0.8%
  – Wyoming average price $25.56/MWh (max $68.94, min $6.86) – increases price by 3.2%
Wyoming/Colorado Price Differentials

- Less than $0.01
- $0.10
- $1
- $2
- $3
- $4
- $5
- $10
- $20
- $30
- More

- With 100MW Increase
- Original constraint
100 MW Transmission increase

- Summer 2008 – longer simulation – 60 runs of hourly wind draws (20,160 simulated hours).
- Reduces price in Colorado, but increases it in Wyoming
  - Average price difference falls by 44% ($2.20 to $1.23)
  - Colorado average price $37.74/MWh (max $77.07, min $16.14) - reduces price in Colorado by 0.3%
  - Wyoming average price $25.56/MWh (max $77.07, min $12.98) – increases price by 2.4%
Simulation Implications

• Nodal pricing – how much does it cost to get it wrong?
  – Green (JRE, 2007)

• Must consider transmission congestion and random nature of wind simultaneously.

• Nodal pricing outcomes can be counter-intuitive if congestion creates inefficient outcomes.
Extensions

• Regional economic effects
  – Model will eventually be incorporated into a regional CGE model to
determine full economic impacts of wind and transmission
development over 20-year period into future.

• Environmental extensions
  – Spatial- Endangered Species Areas (Sage grouse)
  – Institutional – water use and hydro-power

• Climate Variability

• Climate Change Policy
  – Renewable Portfolio standards
  – Emission Tax/Trading

• Infrastructure changes
  – Generation
  – Transmission

• Demand/Demand Management
Death of Foote Creek #11 in high winds, winter 2010

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