EAST COAST ENERGY GROUP

Transmission: How Much Should Be Built? What are the Benefits and Costs?

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Outline

- ICF Background
- Study Overview (Background; Objective)
- Approach
- Results
- Questions
ICF Background
Introduction to ICF Consulting

- 34 years of experience
- Energy and Environmental Consulting
- 1,000+ employees
- $150 million revenue
- Privately owned
- Headquartered in Fairfax, VA
  - Offices on 4 Continents
- Independent analysts and advisors
Study Overview
Significant Shortfall In Transmission Investment

Source: Cambridge CERA Workshop
# One Metric of Shortage Transmission Capacity (TTCs)

<table>
<thead>
<tr>
<th>Year</th>
<th>Region A to Other Surrounding Regions (Non-Simultaneous TTCs/GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1998</td>
<td>1.7</td>
</tr>
<tr>
<td>1999</td>
<td>5.9</td>
</tr>
<tr>
<td>2000</td>
<td>3.7</td>
</tr>
<tr>
<td>2001</td>
<td>5.4</td>
</tr>
<tr>
<td>2003</td>
<td>0.3</td>
</tr>
</tbody>
</table>
Increasing Annual Cost of Congestion - PJM

Total Congestion Costs

Source: PJM ISO
Atomization/Islanding of Grid Has Cost Consequences as Well as Accelerating Market Recovery

<table>
<thead>
<tr>
<th>Market Size</th>
<th>Approximate Required Reserve Margin (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>80 GW</td>
<td>13.5</td>
</tr>
<tr>
<td>55 GW</td>
<td>14.5</td>
</tr>
<tr>
<td>30 GW</td>
<td>15.5</td>
</tr>
<tr>
<td>15 GW</td>
<td>17.5</td>
</tr>
<tr>
<td>10 GW</td>
<td>19.0</td>
</tr>
</tbody>
</table>
Study Objective

- Given the significant shortfall in transmission investment;
  - How much should be invested in transmission
  - What are the potential benefits/costs in making the right transmission investments
Cases Examined

- Base Case – Market As-Is
- Change Cases
  - Optimal Case
  - 25%; 50%; 75%; 125% of Optimal Level of Investment Cases
- Effect of Reserve Sharing Case
Approach
Estimating Additional Transmission Capacity is a Non-Trivial Exercise

- Complexity of Power Flows
- Large Network Externality
- Balancing Reliability and Economic Transmission Capacity Needs
Balancing Market Risks

- Entry and Exit Decision Dynamic
  - Entry from competing generation options
  - Environmental Retrofits
  - Mothballing and Retirements
  - DSM and Response from Loads
- Fuel Price Volatility
- Environmental Regulations and Its Impact on Allowance Prices/Unit Compliance Options
Multi-Model Analytic Platform

PowerWorld
- Optimal power flow
- Contingency analysis
- Load flow
- Stability analysis
- RMR Studies
- Forecasting transmission capacity
- Generation interconnection assessments
- LMP and congestion snapshots

MAPS
- Forecast of
  - Hourly LMPs
  - Hourly transmission Line loadings
  - Hourly Interface loadings
  - Hourly congestion right net revenues
  - Hourly plant dispatch (near-term)
  - Contingency scenarios

IPM
- Capacity additions
- Retirement and mothballing decisions
- Electric prices (Energy, Capacity, OR)
- Asset values
- Emissions
- Retrofit decisions
- Environmental compliance costs

PowerWorld provides MAPS with transmission interface limits and critical transmission contingencies to monitor

IPM provides MAPS with entry and exit decisions and environmental allowance prices

Combination of near- and long-term forecasts of forward markets and asset valuation

PowerWorld forecasts inter-regional transmission capacity (ATC/TTC) for IPM
Estimating Transmission Investments Requires A Fully Integrated Market Study
Treatment of Existing Transmission Capacity

- Assumed existing Transmission Owners will continue to make incremental investments to maintain current transfer capabilities
- Margins reserved for reliability
- Firm transmission capacity was used for economy energy and capacity flows
- Incremental non-firm transmission capacity was used for only additional economy energy flows
- Used non-simultaneous and simultaneous open and closed-loop interface limits
Key Transmission Build Assumptions
**Contribution of New Transmission Capacity to Actual Transfer Capability**

- The right percent contribution depends on several factors including:
  - Network topology
  - Location of generation injections and loads
  - Generation and demand patterns

- 60% was used. For every 1MW of physical transmission capacity, 0.6 MW counts towards firm transmission capacity. Higher or lower percentages may be tested in sensitivity analysis cases.

- Assumed all nodal transmission voltages were maintained within ± 5% of nominal - adequate reactive power compensation for all transmission facilities.

<table>
<thead>
<tr>
<th>Line Voltage (kV)</th>
<th>Mean Capacity(^1) (MVA)</th>
<th>Std. Dev. (^1) (MVA)</th>
<th>68% Confidence Interval(^1) (MVA)</th>
<th>95% Confidence Interval(^1) (MVA)</th>
<th>ICF’s Generic Assumptions (MVA)</th>
<th>Capital Cost(^2) ($/kW-mile)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AC Transmission Lines</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>115</td>
<td>150</td>
<td>197</td>
<td></td>
<td></td>
<td>100 – 175</td>
<td>2.24</td>
</tr>
<tr>
<td>138</td>
<td>203</td>
<td>230</td>
<td></td>
<td></td>
<td>175 – 315</td>
<td>2.00</td>
</tr>
<tr>
<td>230</td>
<td>530</td>
<td>191</td>
<td>340 - 721</td>
<td>149 - 912</td>
<td>316 – 768</td>
<td>1.64</td>
</tr>
<tr>
<td>345</td>
<td>1,073</td>
<td>258</td>
<td>815 – 1,332</td>
<td>557 – 1,590</td>
<td>769 – 1,435</td>
<td>1.17</td>
</tr>
<tr>
<td>500</td>
<td>2,291</td>
<td>754</td>
<td>1,537 - 3,045</td>
<td>784 – 3,799</td>
<td>1,436 – 3,103</td>
<td>0.74</td>
</tr>
<tr>
<td>765</td>
<td>3,803</td>
<td>644</td>
<td>3,160 – 4,447</td>
<td>2,516 – 5,091</td>
<td>3,104 – 5,000</td>
<td>0.50</td>
</tr>
</tbody>
</table>

\(^1\) Source is empirical data of transmission line types and their capacities in U.S. Eastern Interconnect. The thermal capacities referred to above reflect normal limits.


Line costs shown here include the costs of land, towers, poles, and conductors, substations and related equipment, and right of way. Costs do not include the system reinforcement cost of $336/kW that will be modeled.

EEI increased estimates of Seppa by 20 percent to account for the costs of substations and related equipment.

ICF then added costs to include right of way costs.
## Financing Assumptions

<table>
<thead>
<tr>
<th>Input Assumptions</th>
<th>Transmission</th>
<th>CC and Cogen</th>
<th>Coal</th>
<th>CT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Debt Life (years)</td>
<td>20</td>
<td>20</td>
<td>20</td>
<td>15</td>
</tr>
<tr>
<td>Book Life (years)</td>
<td>40</td>
<td>20</td>
<td>20</td>
<td>15</td>
</tr>
<tr>
<td>After Tax Nominal Equity Rate (%)</td>
<td>40</td>
<td>55</td>
<td>40</td>
<td>70</td>
</tr>
<tr>
<td>Equity Rate (%)</td>
<td>40(^1)</td>
<td>55</td>
<td>40</td>
<td>70</td>
</tr>
<tr>
<td>Pre-Tax Nominal Debt Rate (%)</td>
<td>9</td>
<td>8</td>
<td>8</td>
<td>9</td>
</tr>
<tr>
<td>Debt Ratio (%)</td>
<td>60</td>
<td>45</td>
<td>60</td>
<td>30</td>
</tr>
<tr>
<td>Income Tax Rate (%)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Inflation (%)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other Taxes/Insurance – US Average (%)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Output</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Levelized Real Fixed Charge Rate (%)</td>
<td>12.3</td>
<td>13.7</td>
<td>12.0</td>
<td>14.8</td>
</tr>
</tbody>
</table>

\(^1\) Debt and Equity ratios for individual transmission and generation projects may vary.
Results
## Optimal Investment in Transmission Capacity

<table>
<thead>
<tr>
<th></th>
<th>2004-2030 Total (Billion 2003$)</th>
<th>NPV1 2004-2030 (Billion 2003$)</th>
<th>Benefit/Cost Ratio-</th>
</tr>
</thead>
<tbody>
<tr>
<td>Optimal Transmission Investment Cost</td>
<td>$12.0</td>
<td>$8.2</td>
<td>-</td>
</tr>
<tr>
<td>Net Savings in Production Costs Compared to ICF’s Base Case</td>
<td>$9.7</td>
<td>$4.4</td>
<td>1.5</td>
</tr>
<tr>
<td>Net Savings with Benefits from Reserve Sharing</td>
<td>$26.5</td>
<td>$9.7</td>
<td>2.2</td>
</tr>
</tbody>
</table>
Estimated Economic Benefits at Different Levels of Transmission Investment

<table>
<thead>
<tr>
<th>Benefit/Cost Ratio</th>
<th>NPV (Billion 2003 $)</th>
<th>Total Dollars (Billion 2003 $)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Optimal Investment</td>
<td>$0</td>
<td>$-10</td>
</tr>
<tr>
<td>Net Savings</td>
<td>$0.5</td>
<td>$10</td>
</tr>
<tr>
<td>Net Savings with Reserve Sharing</td>
<td>$1</td>
<td>$20</td>
</tr>
</tbody>
</table>

Billion (2003 $)

Benefit/Cost Ratio
Production Costs Savings

NPV of System Cost Savings vs NPV Transmission Investment.
Discounting Period: 2003 - 2030
Discount Rate Applied: 7%
ICF Standard Reserve Margin Forecasts Applied

Optimal Level of Transmission Investment. The highest marginal benefit occurs at this point.
Cumulative Economic Transmission Builds By Investment Year

- Cumulative MW of Transmission Built
- Cumulative Investment (Billions of 2003$)

MW Built
Billions Invested


- 2004-2007: 10,000 MW, $0.5 billion
- 2008-2011: 20,000 MW, $2.0 billion
- 2012-2017: 30,000 MW, $4.5 billion
- 2018-2025: 40,000 MW, $7.0 billion
- 2028-2030: 50,000 MW, $9.5 billion

Cumulative investment and MW built increase significantly over the years, indicating a growing economic transmission builds.
Economic Generation Additions
Additional Benefits From Reserve Sharing

![Graph showing Estimated Savings Base Case and Estimated Savings When Reserve Sharing is Considered. The graph indicates a significant increase in NPV System Cost Savings when reserve sharing is considered.]