WHOLESALE ELECTRICITY MARKET DEVELOPMENTS IN THE U.S.

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Cambridge, England
July 14, 2004

MIT CEEPR
Cambridge-MIT Institute Electricity Project
THE UNITED STATES

• Big country
• 50 states
• Diverse energy resources and costs
• Electric power sector organization and regulation was historically primarily the responsibility of the states
• Federal (FERC) historical role very small and its statutory authority modest
• Liberalization involves major increase of federal over state regulatory authority, creating state-federal tensions
• No broad national commitment to liberalization of the electricity sector. Very diverse regional views
• California mess in 2000-2001 slowed down reforms in other states
• August 2003 blackout is being used by opponents of further reform
U.S. REGULATORY FRAMEWORK

• Federal: FERC (Federal Power Act of 1935)
  – Wholesale power transactions (not sales to end-users)
  – Interstate “unbundled” transmission access and pricing
  – Utility mergers
  – Market-based pricing authority (under J&R standard)
  – Has used limited statutory authority aggressively

• States: 49 State PUCs (+DC)
  – Local distribution franchises
  – Retail competition/procurement framework
  – Utility organization (Vertical integration)
  – Retail power prices and supporting costs (G +T+G)
  – Transmission investment approvals
  – Full unbundling of T&D for retail sales
North American Electric Power Grids

Source: NERC
LIBERALIZATION MILESTONES

• Energy Policy Act of 1992
  – FERC authority over transmission service expanded
  – Unregulated generating plants supported (EWG)

• FERC Order 888/889 (1996)
  – Open Access Transmission Tariffs
  – OASIS

• FERC Order 2000 (December 1999)
  – Formation of Regional Transmission Operators (RTOs)
  – Basic Wholesale Market and Transmission Pricing Principles

  – “PJM” for All

  – FERC Backs off SMD and returns to Order 2000

• Generator Interconnection Rules (2003)
STATUS OF COMPREHENSIVE RESTRUCTURING PROGRAMS: STATES

Divestiture Suspended 8/30/02

Retail comp for Industrials only

Divestiture delayed

Source: EIA
U.S. WHOLESALE MARKET CHANGES

• About 650,000 Mw of U.S. generating capacity in 1996 (75% IOU), almost all of it regulated and integrated with T&D

• 100,000 Mw divested and deregulated by 2003

• 85,000 Mw transferred to unregulated affiliates by 2003

• 175,000 Mw of new generating capacity (80% merchant) added between 2000 and 2003

• Large increase in wholesale trade. About 35% of electricity is produced by unregulated generators today (45% of IOU generation)

• Wholesale market prices have declined after controlling for fuel price changes
Average Electricity Prices 1960-2003 ($1996)

Source: EIA
LIBERALIZATION IS NOW MOVING FORWARD SLOWLY

• Restructuring and competition at wholesale and retail levels is still in transition and varies widely from state to state and region to region

• Development of important wholesale market institutions is incomplete in large portions of the country

• No comprehensive Federal restructuring, competition and deregulation initiatives have been passed by Congress

• States have taken their own individual paths with FERC trying to knit together consistent transmission access, pricing and wholesale market rules

• Vertically integrated regulated monopoly model and competitive models are trying to operate simultaneously but very uneasily on the same physical networks

• Incompatible market and regulatory structures operating on the same physical electric power network creates very significant challenges!
Source: EIA
FOCUS ON THE NORTHEASTERN MARKETS

• New England, New York and PJM
• Best articulations of FERC’s RTO and SMD visions
• Retail competition in all states but Vermont
• Continued state commitments to restructuring and competition
• Several years of experience
• California and MISO will adopt similar market designs
• PJM expanding West to include portions of Ohio, West Virginia, Indiana, and Virginia as well as Northern Illinois
PJM RTO 2004 AND INTERCONNECTIONS
PJM RTO 2004

Source: PJM
BASIC ATTRIBUTES OF NORTHEASTERN RTO/ISOs

• Independent System Operator
  – Non-profit entity that does not own transmission assets
  – Responsible for operating reliability of network
  – Control area operator
  – Manages Open Access Transmission Tariff and OASIS
  – Manages voluntary wholesale markets for power and ancillary services
  – Manages requests for transmission service, allocation of scarce transmission capacity and network expansions
  – Regional Transmission Expansion Planning process
  – Market monitoring and mitigation programs
  – Coordination with neighboring control areas, including imports/exports (cross-border trade)

• Regulated Incumbent Transmission Owners (TO)
  – Functional separation rules due to vertical integration
  – Opportunities for merchant projects
BASIC FEATURES OF WHOLESALE MARKET DESIGN

• Security constrained bid-based dispatch using state-estimator network model
  – Day-ahead hourly markets
  – Real-time market (adjustments, imbalances, 5-minutes)
  – Self-scheduling permitted subject to imbalance and congestions charges

• Resulting LMPs calculated at each bus
  – Marginal cost of congestion
  – Marginal cost of losses (not yet in PJM)

• Market-based provision of ancillary services integrated with day-ahead and real-time energy markets

• All transmission service customers must pay costs of congestion based on differences in LMPs between source and sink of power transactions
  – Day-ahead
  – Real-time
BASIC FEATURES OF WHOLESALE MARKET

• Financial Transmission Rights (FTRs) allocated (theoretically) consistent with network feasibility constraints
  – Rights to proportionate share of congestion rents
  – Initial allocation based on transmission ownership to serve “native load,” third-party contracts for firm transmission service or investment in new T capacity
  – FTRs are tradable and there are reconfiguration opportunities
  – Auctions (annual, monthly) and Auction Revenue Rights (PJM)
  – Obligation rights, option rights, peak, off-peak rights (PJM)

• Generating capacity (reserve) obligations imposed on LSE (e.g. 18% forward reserve margin)
  – Load reduction capabilities are eligible
  – Capacity resources must meet deliverability criteria (PJM)
  – Designated capacity resources must make energy available to the SO through bids
MARKET MONITORING AND MITIGATION

- $1000/MWh general bid cap
- Local market power mitigation rules
  - Bid caps
  - RMR contracts
  - Must-offer restrictions
  - Interaction with computation of market prices
- Must offer requirements
- Ex-post bid/price adjustments
- Monitoring of individual market participant behavior and market performance
TRANSMISSION PRICING (PJM)

• Firm Network Integration Service
  – Designed to replicate transmission service available “internally” to vertically integrated LSEs in PJM with their own T networks.
  – LSE’s transmission service price equals average total cost of transmission network per MW of peak load based on cost of transmission facilities in load areas (license plate tariff --- $15-$25/KW-year) + network enhancement charges, if any
  – Cost-of-service rate of return regulation determines prices. No PBR for operating costs, availability, outage response (yet)
  – Transmission customers pay congestion charges and losses.
  – Receive FTRs/ARRs for designated sources and sinks

• Firm point-to-point service
  – Imports, exports, transit, internal transactions not otherwise covered by network integration service
  – Term: one day to one year (short-term). One year or more by agreement (long term).
  – Average total cost of transmission system in delivery area ($15 - $25/KW-year) or PJM border + enhancement charges
  – Receive FTR/ARR allocation
  – Responsible for congestion charges and allocation of losses
TRANSMISSION PRICING (PJM)

• Non-firm point-to-point service
  – Term: One hour to one-month
  – Curtained first to relieve congestion with option to pay congestion charges and avoid curtailment
  – Same average total cost-based price per Kw-time as firm but no network enhancement charges (can be discounted)
  – Hourly on-peak transmission service fee averages about $5/Mwh on peak
  – Loss charges are added
  – No FTRs included
TRANSMISSION PRICING (PJM)

• Transmission charges paid by generators and merchant transmission projects
  – Direct interconnection costs
  – Incremental network upgrade costs to maintain MAAC reliability criteria (incremental FTRs allocated)
    • Sharing protocol for groups of new generators
  – Incremental network upgrade costs to meet MAAC deliverability criteria to be certified as a “capacity resource” (incremental FTRs allocated)
  – Congestion charges and losses only if the generator is also providing supporting transmission service for the transaction or by agreement with buyer (e.g. an export by a merchant generator)
$/MCF

Source: EIA
## Table 2-23  PJM Average Hourly Locational Marginal Prices (in Dollars per MWh)

<table>
<thead>
<tr>
<th>Year</th>
<th>Average</th>
<th>Median</th>
<th>Standard Deviation</th>
<th>Average LMP</th>
<th>Median LMP</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>2003</td>
<td>$38.27</td>
<td>$30.79</td>
<td>$24.71</td>
<td>35.2%</td>
<td>46.0%</td>
<td>10.3%</td>
</tr>
<tr>
<td>2002</td>
<td>$28.30</td>
<td>$21.08</td>
<td>$22.40</td>
<td>-12.6%</td>
<td>-8.3%</td>
<td>-50.6%</td>
</tr>
<tr>
<td>2001</td>
<td>$32.38</td>
<td>$22.98</td>
<td>$45.30</td>
<td>15.1%</td>
<td>20.3%</td>
<td>76.3%</td>
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<tr>
<td>2000</td>
<td>$28.14</td>
<td>$19.11</td>
<td>$25.69</td>
<td>-0.6%</td>
<td>6.9%</td>
<td>-64.5%</td>
</tr>
<tr>
<td>1999</td>
<td>$28.32</td>
<td>$17.88</td>
<td>$72.41</td>
<td>30.4%</td>
<td>7.7%</td>
<td>130.2%</td>
</tr>
<tr>
<td>1998</td>
<td>$21.72</td>
<td>$16.60</td>
<td>$31.45</td>
<td></td>
<td></td>
<td></td>
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</tbody>
</table>

Source: PJM State of Markets 2003
<table>
<thead>
<tr>
<th></th>
<th>2003</th>
<th>2002</th>
<th>Percent Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average LMP</td>
<td>$28.60</td>
<td>$31.60</td>
<td>-9.5%</td>
</tr>
<tr>
<td>Median LMP</td>
<td>$24.40</td>
<td>$23.41</td>
<td>4.2%</td>
</tr>
<tr>
<td>Standard Deviation</td>
<td>$16.94</td>
<td>$26.74</td>
<td>-36.6%</td>
</tr>
</tbody>
</table>

Source: PJM State of Markets 2003
<table>
<thead>
<tr>
<th></th>
<th>22-Aug-03</th>
<th>14-Aug-02</th>
<th>9-Aug-01</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Demand (MW)</td>
<td>61,500</td>
<td>63,762</td>
<td>62,232</td>
</tr>
<tr>
<td>Maximum Daily LMP ($ per MWh)</td>
<td>$95.11</td>
<td>$445.30</td>
<td>$932.30</td>
</tr>
<tr>
<td>Average PJM LMP ($ per MWh)</td>
<td>$58.47</td>
<td>$88.00</td>
<td>$387.70</td>
</tr>
<tr>
<td>Average Peak PJM LMP ($ per MWh)</td>
<td>$65.89</td>
<td>$122.30</td>
<td>$559.40</td>
</tr>
<tr>
<td>Average Off Peak PJM LMP ($ per MWh)</td>
<td>$43.61</td>
<td>$19.20</td>
<td>$44.20</td>
</tr>
</tbody>
</table>

Source: PJM State of Markets 2003
### Table 2-27: Comparison of Real-Time and Day-Ahead 2003 Market LMP (in Dollars per MWh)

<table>
<thead>
<tr>
<th></th>
<th>Day-Ahead</th>
<th>Real-Time</th>
<th>Difference</th>
<th>Difference as Percent Real-Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average LMP</td>
<td>$38.72</td>
<td>$38.27</td>
<td>-$0.45</td>
<td>-1.2%</td>
</tr>
<tr>
<td>Median LMP</td>
<td>$35.21</td>
<td>$30.79</td>
<td>-$4.43</td>
<td>-14.4%</td>
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<tr>
<td>Standard Deviation</td>
<td>$20.84</td>
<td>$24.71</td>
<td>$3.87</td>
<td>15.7%</td>
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</table>

Source: PJM State of Markets 2003
### Table 2-33 2003 Demand-Side Response Program

<table>
<thead>
<tr>
<th>PJM Programs</th>
<th>MW Registered</th>
</tr>
</thead>
<tbody>
<tr>
<td>PJM Economic Load-Response Program</td>
<td>724</td>
</tr>
<tr>
<td>PJM Emergency Load-Response Program</td>
<td>659</td>
</tr>
<tr>
<td>PJM Active Load-Management Resources</td>
<td>1,207</td>
</tr>
<tr>
<td>PJM ALM Resources Included in Load-Response Program</td>
<td>(445)</td>
</tr>
<tr>
<td><strong>Total PJM Programs</strong></td>
<td>2,145</td>
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</tbody>
</table>

Source: PJM State of Markets 2003
Table 24 – Quarterly Statistics for Daily All-In Price of Wholesale Electricity ($/MWh)

<table>
<thead>
<tr>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1999 Q2</td>
<td>$39.40</td>
<td>$29.07</td>
<td>$232.37</td>
<td>$23.54</td>
<td>$42.09</td>
</tr>
<tr>
<td>2000 Q2</td>
<td>$44.31</td>
<td>$33.45</td>
<td>$1,219.56</td>
<td>$20.18</td>
<td>$107.72</td>
</tr>
<tr>
<td>2001 Q2</td>
<td>$42.31</td>
<td>$41.96</td>
<td>$91.41</td>
<td>$17.11</td>
<td>$11.59</td>
</tr>
<tr>
<td>2002 Q2</td>
<td>$32.43</td>
<td>$32.02</td>
<td>$52.22</td>
<td>$19.12</td>
<td>$5.80</td>
</tr>
<tr>
<td>2003 Q2</td>
<td>$52.65</td>
<td>$46.47</td>
<td>$150.24</td>
<td>$34.04</td>
<td>$18.45</td>
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</table>

Source: ISO New England
<table>
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<tr>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
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<tbody>
<tr>
<td>Maine</td>
<td>$68.02</td>
<td>$42.50</td>
<td>$40.83</td>
<td>$42.44</td>
<td>$43.17</td>
<td>$40.05</td>
<td>$37.85</td>
<td>$41.51</td>
<td>$38.51</td>
<td>$46.33</td>
</tr>
<tr>
<td>New Hampshire</td>
<td>$68.27</td>
<td>$46.89</td>
<td>$43.86</td>
<td>$46.20</td>
<td>$47.06</td>
<td>$43.44</td>
<td>$40.64</td>
<td>$43.46</td>
<td>$40.86</td>
<td>$49.72</td>
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<tr>
<td>Vermont</td>
<td>$69.65</td>
<td>$47.93</td>
<td>$45.38</td>
<td>$47.79</td>
<td>$49.22</td>
<td>$45.66</td>
<td>$41.96</td>
<td>$44.92</td>
<td>$42.27</td>
<td>$50.70</td>
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<tr>
<td>Connecticut</td>
<td>$70.07</td>
<td>$48.80</td>
<td>$50.00</td>
<td>$50.75</td>
<td>$52.50</td>
<td>$51.85</td>
<td>$44.52</td>
<td>$49.05</td>
<td>$48.88</td>
<td>$54.58</td>
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<tr>
<td>Rhode Island</td>
<td>$67.37</td>
<td>$45.64</td>
<td>$45.60</td>
<td>$46.90</td>
<td>$46.47</td>
<td>$44.68</td>
<td>$40.13</td>
<td>$43.41</td>
<td>$41.46</td>
<td>$50.82</td>
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<td>SEMASS</td>
<td>$67.09</td>
<td>$45.80</td>
<td>$45.76</td>
<td>$46.68</td>
<td>$46.72</td>
<td>$43.23</td>
<td>$39.88</td>
<td>$43.22</td>
<td>$41.45</td>
<td>$49.88</td>
</tr>
<tr>
<td>WCMass</td>
<td>$69.28</td>
<td>$46.62</td>
<td>$46.01</td>
<td>$47.80</td>
<td>$48.17</td>
<td>$44.53</td>
<td>$41.74</td>
<td>$44.22</td>
<td>$42.20</td>
<td>$51.33</td>
</tr>
<tr>
<td>NEMA/Boston</td>
<td>$71.23</td>
<td>$48.07</td>
<td>$47.62</td>
<td>$49.30</td>
<td>$49.06</td>
<td>$46.65</td>
<td>$43.11</td>
<td>$46.31</td>
<td>$43.51</td>
<td>$51.48</td>
</tr>
<tr>
<td>System Overall</td>
<td>$71.44</td>
<td>$47.46</td>
<td>$46.64</td>
<td>$47.43</td>
<td>$48.66</td>
<td>$46.74</td>
<td>$42.31</td>
<td>$45.83</td>
<td>$44.00</td>
<td>$51.62</td>
</tr>
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Source: ISO New England
Monthly Average Day-Ahead and Real-Time Hub LMPs
March - December 2003

Source: ISO New England
Figure 15 – DA vs. RT LMP Price Convergence at the Hub
March - June 2003

Source: ISO New England
Figure 4: Day-Ahead Energy Prices in 2003

Figure 7: Average All-In Price in 2002 and 2003

Capital Zone -- 2003

Source: New York ISO
Figure 11: Day-Ahead and Real-Time Prices in New York City
2002 and 2003

Figure 27: Day-Ahead Congestion Costs and TCC Payments
2001-2003

Revenue Shortfall
2001: $49 Million
2002: $77 Million
2003: $126 Million

Figure 13: Frequency of Real-Time Constraints and Mitigation
New York City Load Pockets, 2003

Average Hourly RT Energy Clearing Prices (Weekdays)

December 2003

Source: ISO New England
Figure 20 - Average Hourly RT Energy Prices, NE, NY and PJM
Weekdays, March-June, 2003

Source: ISO New England
Figure 3-10  Daily Hourly Average Price Difference (NY Proxy - PJM/NYIS)

## FORWARD MARKETS
### $/Mwh 6x16 Contract
#### (June 30, 2004)

<table>
<thead>
<tr>
<th>Delivery Location</th>
<th>July 04</th>
<th>Aug 04</th>
<th>Q4-04</th>
<th>June 05</th>
<th>Cal 05</th>
<th>Cal 06</th>
</tr>
</thead>
<tbody>
<tr>
<td>MA Hub</td>
<td>70.0</td>
<td>72.0</td>
<td>62.75</td>
<td>61.0</td>
<td>64.75</td>
<td>60.0</td>
</tr>
<tr>
<td>NY Zone A</td>
<td>61.25</td>
<td>63.0</td>
<td>-</td>
<td>-</td>
<td>55.75</td>
<td>-</td>
</tr>
<tr>
<td>NY Zone G</td>
<td>74.0</td>
<td>76.0</td>
<td>-</td>
<td>-</td>
<td>66.25</td>
<td>-</td>
</tr>
<tr>
<td>NY Zone J</td>
<td>99.0</td>
<td>100.0</td>
<td>-</td>
<td>-</td>
<td>83.25</td>
<td>-</td>
</tr>
<tr>
<td>PJM West</td>
<td>64.6</td>
<td>67.0</td>
<td>50.25</td>
<td>53.25</td>
<td>52.5</td>
<td>49.75</td>
</tr>
<tr>
<td>Cinergy</td>
<td>52.3</td>
<td>54.8</td>
<td>40.8</td>
<td>46.3</td>
<td>45.9</td>
<td>43.0</td>
</tr>
</tbody>
</table>

Source: Platt’s *Megawatt Daily*, June 30, 2004
### Table 2-17  New Entrant Combustion Turbine and Combined-Cycle Plant Theoretical Net Revenues

<table>
<thead>
<tr>
<th>Year</th>
<th>CT Energy</th>
<th>CC Energy</th>
<th>Capacity</th>
<th>Ancillary</th>
<th>CT Total</th>
<th>CC Total</th>
<th>CT Run Hours</th>
<th>CC Run Hours</th>
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</thead>
<tbody>
<tr>
<td>2003</td>
<td>$15,380</td>
<td>$53,743</td>
<td>$5,936</td>
<td>$3,880</td>
<td>$25,196</td>
<td>$63,559</td>
<td>964</td>
<td>2,791</td>
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<tr>
<td>2002</td>
<td>$27,626</td>
<td>$57,148</td>
<td>$11,601</td>
<td>$3,915</td>
<td>$43,142</td>
<td>$72,664</td>
<td>1,383</td>
<td>3,206</td>
</tr>
<tr>
<td>2001</td>
<td>$44,481</td>
<td>$74,831</td>
<td>$36,700</td>
<td>$3,823</td>
<td>$85,004</td>
<td>$115,354</td>
<td>1,373</td>
<td>3,507</td>
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<tr>
<td>2000</td>
<td>$19,876</td>
<td>$45,236</td>
<td>$23,308</td>
<td>$4,594</td>
<td>$47,779</td>
<td>$73,138</td>
<td>926</td>
<td>2,201</td>
</tr>
<tr>
<td>1999</td>
<td>$73,480</td>
<td>$97,603</td>
<td>$20,469</td>
<td>$3,444</td>
<td>$97,393</td>
<td>$121,516</td>
<td>1,415</td>
<td>4,199</td>
</tr>
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</table>

**Average Net Revenues/MW-year (1999-2003)**

<table>
<thead>
<tr>
<th></th>
<th><strong>Total</strong></th>
<th><strong>Energy Only</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CT</strong></td>
<td>$60,000</td>
<td>$36,000</td>
</tr>
<tr>
<td><strong>CC</strong></td>
<td>$90,000</td>
<td>$60,640</td>
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</tbody>
</table>

Source: PJM State of Markets 2003
### SCARCITY RENTS PRODUCED DURING OP-4 CONDITIONS ($1000 Price Cap) ($/Mw-Year)

<table>
<thead>
<tr>
<th>YEAR</th>
<th>ENERGY MC=50</th>
<th>ENERGY MC=100</th>
<th>OPERATING RESERVES</th>
<th>OP-4 HOURS/ (Price Cap Hit)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002</td>
<td>$ 5,070</td>
<td>$ 4,153</td>
<td>$ 4,723</td>
<td>21 (3)</td>
</tr>
<tr>
<td>2001</td>
<td>$15,818</td>
<td>$14,147</td>
<td>$11,411</td>
<td>41 (15)</td>
</tr>
<tr>
<td>2000</td>
<td>$ 6,528</td>
<td>$ 4,241</td>
<td>$ 4,894</td>
<td>25 (5)</td>
</tr>
<tr>
<td>1999</td>
<td>$18,874</td>
<td>$14,741</td>
<td>$19,839</td>
<td>98 (1)</td>
</tr>
<tr>
<td>Mean</td>
<td>$11,573</td>
<td>$ 9,574</td>
<td>$10,217</td>
<td>46 (6)</td>
</tr>
</tbody>
</table>

Peaker Fixed-Cost Target: $60,000 - $70,000/Mw-year
Figure 14: Estimated Net Revenue in the Day-Ahead Market
2002 - 2003

# PJM Congestion Event Hours

<table>
<thead>
<tr>
<th>YEAR</th>
<th>TOTAL</th>
<th>500kv</th>
<th>345kv</th>
<th>230kv</th>
</tr>
</thead>
<tbody>
<tr>
<td>1998</td>
<td>1,244</td>
<td>203</td>
<td>71</td>
<td>588</td>
</tr>
<tr>
<td>1999</td>
<td>2,134</td>
<td>189</td>
<td>148</td>
<td>818</td>
</tr>
<tr>
<td>2000</td>
<td>6,941</td>
<td>562</td>
<td>14</td>
<td>869</td>
</tr>
<tr>
<td>2001</td>
<td>8,435</td>
<td>759</td>
<td>38</td>
<td>744</td>
</tr>
<tr>
<td>2002</td>
<td>11,662</td>
<td>1,888</td>
<td>1,084</td>
<td>1,474</td>
</tr>
<tr>
<td>2003</td>
<td>9,711</td>
<td>1,985</td>
<td>705</td>
<td>3,016</td>
</tr>
</tbody>
</table>

Source: *PJM State of the Market Report 2002 and 2003*
<table>
<thead>
<tr>
<th>Year</th>
<th>PJM Congestion Costs (RENTS) ($ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1999</td>
<td>53</td>
</tr>
<tr>
<td>2000</td>
<td>132</td>
</tr>
<tr>
<td>2001</td>
<td>271</td>
</tr>
<tr>
<td>2002</td>
<td>430</td>
</tr>
<tr>
<td>2003</td>
<td>499</td>
</tr>
</tbody>
</table>

Source: PJM *State of the Market Report 2002 and 2003*
<table>
<thead>
<tr>
<th>Year</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>2001</td>
<td>$310 million</td>
</tr>
<tr>
<td>2002</td>
<td>$525 million</td>
</tr>
<tr>
<td>2003</td>
<td>$688 million</td>
</tr>
</tbody>
</table>
TRANSMISSION INVESTMENT
PJM

• Heavy Influenced by legacy reliability rules and their implementation in the old regime

• Various Categories of investment
  – Direct Interconnection of generators or merchant transmission
  – Interconnection Network Upgrades to restore reliability parameters
  – Deliverability Network Upgrades
  – Other system reliability network upgrades
  – “Economic” upgrades
  – Merchant transmission

• Mediated through regional transmission planning process
TRANSMISSION INVESTMENT
PJM

• MAAC has a complex hierarchy of reliability rules that are applied at the system level and to specific geographic areas (transmission zones)

• Engineering models are used to evaluate the system under various assumptions that bear no relationship to economic dispatch or congestion management
  – e.g. incumbent generators assumed to run to meet peak load and then generator being studied is assumed to run at peak capacity

• Distinctions between “reliability” investments and “economic” investments are quite arbitrary (e.g. generator deliverability)

• A significant fraction of “reliability” investments are really “economic” investments as they are modeled by economists

• New York and New England apply different reliability and economic considerations for transmission investment
PJM (MAAC) RELIABILITY RULES

- Normal system operating conditions
- N-1
- N-2
- Multiple Facility Contingency
- Generator deliverability
- Deliverability to load
TRANSMISSION INVESTMENT
PJM

• TO in affected area designs, owns and operates transmission facilities approved in RTEP except for merchant transmission facilities which TO may also own

• Generators pay regulated cost of service prices for:
  – Direct interconnection facilities
  – Interconnection Network upgrades (incremental FTRs)
  – Deliverability network upgrades (incremental FTRs)

• LSEs shares costs of other reliability mandated network upgrades

• Merchants design, own, operate and pay for new merchant facilities and get FTRs for AC enhancements

• Costs of “economic” planned transmission facilities are shared by LSEs with customers who benefit from upgrades (recent addition still in process)
TRANSMISSION INVESTMENT PLANS
PJM RTEP (11/03)

• Direct interconnection: $275 million
• Interconnection reliability and deliverability network upgrades: $214 million
• Other network reliability upgrades: $197 million
• Economic upgrades: (in process)
• Merchant
  – None completed to date and several proposals withdrawn
  – Most active projects are HVDC interconnects with New York or Long Island (supported by long term contract with LIPA)
  – Three transformer projects (one inside the fence of a refinery and two by incumbent TO) in development
TRANSMISSION INVESTMENT PLANS
ISO NEW ENGLAND (11/03)

• Interconnection + Reliability + Economic Benefit: $1.5 – $3.0 billion
• Mostly “reliability”
• All regulated projects
NORTHEASTERN MARKET ISSUES

• Seams Issues
  – Better integrate energy and ancillary services markets
  – Framework for expanding interconnections between control areas (merchant is now the only option)

• Local market power problems and solutions

• Incentives for investment in new generating capacity

• Implementation of “resource adequacy” obligations in the presence of retail competition

• Transmission investment framework

• Reliability and markets relationships

• Incentive regulation (PBR) to control transmission operating costs and improve reliability of transmission facilities

• Expand demand-side participation in the wholesale market
  – priority curtailment contracts
  – real time pricing