WHOLESALE ELECTRICITY MARKET DEVELOPMENTS IN THE U.S.

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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 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
  – Wholesale power transactions (not sales to end-users)
  – Interstate 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
MAJOR CONTROL AREAS
Source: EEI
LIBERALIZATION MILESTONES

  - FERC authority over transmission service
  - Unregulated generating plants (EWG)
- **FERC Order 888/889 (1996)**
  - Open Access Transmission Tariffs
  - OASIS
- **FERC Order 2000 (December 1999)**
  - Formation of RTOs
  - Basic Wholesale Market and Transmission Pricing Principles
  - “PJM” for All
  - FERC Backs off SMD and return to Order 2000
- **Generator Interconnection Rules (2003)**
Average Electricity Prices 1960-2003 ($1996)

Source: EIA
% Change in Nominal Residential Retail Price (1995-2002)
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
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!
LIBERALIZATION IS NOW MOVING FORWARD SLOWLY

• Grid management remains highly balkanized with many hands controlling portions of the same synchronized AC network in the East and West

• Many transmission owners and control area operators continue to own proximate generation (VI)

• FERC’s efforts to create large RTOs with standard market, planning and congestion management rules elsewhere has faced considerable opposition though it continues to progress

• Economic and siting regulation is split between federal and state jurisdiction with no PBR and great uncertainty over who pays what to whom and when
FERC’S INITIAL RTO VISION (2000)
STATUS OF COMPREHENSIVE RESTRUCTURING PROGRAMS: STATES

Retail comp for Industrials only

Divestiture Suspended 8/30/02

Divestiture delayed

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
PJM RTO 2004

PJM Transmission Zones
For Regional Transmission Services, In To, Out Of or Thru NEPOOL, click on the NRTG Bubble.
For Transmission Services between New Brunswick and MEPC and/or MPSC, click on the MEPC or MPSC Transmission Provider Bubbles.
For Transmission Services between NEPOOL and Hydro Quebec, click on the Phase I & II Bubble.
For Local Point to Point Transmission Services, click on the individual Transmission Providers bubbles within New England.
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
  – Manages 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 market
  – 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.
  – T 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
  – Curtailed 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

$/MCF

Source: EIA
Figure 2-27  PJM Price Duration Curves – Real-Time Market: 1998 - 2003

Source: PJM State of Markets 2003
Figure 2-28  PJM Price Duration Curves – Real-Time Market – Hours above the 95th Percentile: 1998 - 2003

Source: PJM State of Markets 2003
### Table 2-23  PJM Average Hourly Locational Marginal Prices (in Dollars per MWh)

<table>
<thead>
<tr>
<th>Year</th>
<th>Average LMP</th>
<th>Median LMP</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>
</tr>
<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>
</tr>
</tbody>
</table>

Source: PJM State of Markets 2003
## Table 2-26  
PJM Load-Weighted, Fuel-Cost-Adjusted LMP (in Dollars per MWh)

<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>
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<tr>
<td>Median LMP</td>
<td>$24.40</td>
<td>$23.41</td>
<td>4.2%</td>
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<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 C-5

2002 and 2003 Load-Weighted Average LMP During Constrained and Unconstrained Hours (in Dollars per MWh)

<table>
<thead>
<tr>
<th></th>
<th>Unconstrained Hours</th>
<th>2003</th>
<th>Constrained Hours</th>
<th>Percent Difference</th>
<th>Unconstrained Hours</th>
<th>2002</th>
<th>Constrained Hours</th>
<th>Percent Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average LMP</td>
<td>$34.87</td>
<td>$45.77</td>
<td>31.2%</td>
<td>$31.60</td>
<td>$36.90</td>
<td>16.8%</td>
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<tr>
<td>Median LMP</td>
<td>$25.24</td>
<td>$41.77</td>
<td>65.5%</td>
<td>$23.41</td>
<td>$29.18</td>
<td>24.6%</td>
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<tr>
<td>Standard Deviation</td>
<td>$24.84</td>
<td>$24.81</td>
<td>-0.1%</td>
<td>$26.74</td>
<td>$30.93</td>
<td>15.7%</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: PJM State of Markets 2003
### Table 2-1  Peak PJM Demand Days: 2001, 2002 and 2003

<table>
<thead>
<tr>
<th></th>
<th>22-Aug-03</th>
<th>14-Aug-02</th>
<th>9-Aug-01</th>
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<tbody>
<tr>
<td>Peak Demand (MW)</td>
<td>61,500</td>
<td>63,762</td>
<td>62,232</td>
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<tr>
<td>Maximum Daily LMP ($ per MWh)</td>
<td>$95.11</td>
<td>$445.30</td>
<td>$932.30</td>
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<tr>
<td>Average PJM LMP ($ 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>
</tr>
<tr>
<td>Standard Deviation</td>
<td>$20.84</td>
<td>$24.71</td>
<td>$3.87</td>
<td>15.7%</td>
</tr>
</tbody>
</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>
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<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><strong>2,145</strong></td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
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<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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</tbody>
</table>

Source: ISO New England
## All In Price by Load Zone and System, Month Averages

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
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</thead>
<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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<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>
</tr>
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<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>
</tr>
<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>
</tr>
<tr>
<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>
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<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>
</tbody>
</table>

Source: ISO New England
### DA Nodal LMP Component Summary Statistics by Load Zone, December 2003

<table>
<thead>
<tr>
<th>Nodal Prices</th>
<th>CT</th>
<th>Maine</th>
<th>NEMA</th>
<th>NH</th>
<th>RI</th>
<th>SEMA</th>
<th>VT</th>
<th>WCMA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Un-weighted Average LMP</td>
<td>$51.92</td>
<td>$46.69</td>
<td>$51.67</td>
<td>$50.87</td>
<td>$51.35</td>
<td>$50.60</td>
<td>$52.29</td>
<td>$51.76</td>
</tr>
<tr>
<td>Median LMP</td>
<td>$51.73</td>
<td>$46.43</td>
<td>$51.48</td>
<td>$50.56</td>
<td>$51.29</td>
<td>$50.38</td>
<td>$51.67</td>
<td>$51.56</td>
</tr>
<tr>
<td>Minimum LMP</td>
<td>$17.00</td>
<td>$15.46</td>
<td>$17.71</td>
<td>$16.73</td>
<td>$17.46</td>
<td>$17.47</td>
<td>$5.73</td>
<td>$17.14</td>
</tr>
<tr>
<td>Maximum LMP</td>
<td>$95.92</td>
<td>$200.72</td>
<td>$145.44</td>
<td>$107.87</td>
<td>$91.69</td>
<td>$109.97</td>
<td>$160.29</td>
<td>$125.47</td>
</tr>
<tr>
<td>Average Congestion Component</td>
<td>$0.23</td>
<td>-$0.82</td>
<td>$0.10</td>
<td>-$0.08</td>
<td>$0.10</td>
<td>$0.05</td>
<td>$0.88</td>
<td>$0.14</td>
</tr>
<tr>
<td>Median Congestion Component</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
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<tr>
<td>Minimum Congestion Component</td>
<td>-$11.85</td>
<td>-$29.67</td>
<td>-$17.05</td>
<td>-$14.66</td>
<td>-$9.03</td>
<td>-$41.86</td>
<td>-$63.31</td>
<td>-$10.77</td>
</tr>
<tr>
<td>Maximum Congestion Component</td>
<td>$19.16</td>
<td>$146.73</td>
<td>$73.26</td>
<td>$52.64</td>
<td>$2.66</td>
<td>$51.93</td>
<td>$102.76</td>
<td>$51.47</td>
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<tr>
<td>Average Loss Component</td>
<td>$0.68</td>
<td>-$3.50</td>
<td>$0.52</td>
<td>-$0.07</td>
<td>$0.24</td>
<td>-$0.46</td>
<td>$0.40</td>
<td>$0.60</td>
</tr>
<tr>
<td>Median Loss Component</td>
<td>$0.60</td>
<td>-$3.06</td>
<td>$0.46</td>
<td>-$0.22</td>
<td>$0.33</td>
<td>-$0.52</td>
<td>$0.37</td>
<td>$0.34</td>
</tr>
<tr>
<td>Minimum Loss Component</td>
<td>-$3.67</td>
<td>-$11.19</td>
<td>-$0.94</td>
<td>-$5.53</td>
<td>-$3.52</td>
<td>-$2.96</td>
<td>-$5.35</td>
<td>-$3.46</td>
</tr>
<tr>
<td>Maximum Loss Component</td>
<td>$6.41</td>
<td>$0.93</td>
<td>$3.62</td>
<td>$5.06</td>
<td>$2.33</td>
<td>$3.26</td>
<td>$3.04</td>
<td>$8.34</td>
</tr>
</tbody>
</table>

Source: ISO New England
Daily Average All-In Price of Wholesale Electricity vs Variable Production Costs

Correlation Coefficient of Energy Price and Var Gas = 0.81

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

March - June 2003

Source: ISO New England
Figure 2: Price Duration Curve – All Hours
Average Real-Time Price 2001-2003

Figure 3: Price Duration Curves – Highest 5 Percent of Hours
New York State Average Real-Time Price
Figure 4: Day-Ahead Energy Prices in 2003

- West
- East Upstate
- NYCLI
Figure 7: Average All-In Price in 2002 and 2003

- **State**
  - 2002: $50
  - 2003: $70

- **NYC**
  - 2002: $40
  - 2003: $90

- **East above NYC**
  - 2002: $30
  - 2003: $60

- **West**
  - 2002: $20
  - 2003: $50

Legend:
- **Ancillary Services and Other**
- **Uplift**
- **Energy Price**
- **Capacity**
Figure 11: Day-Ahead and Real-Time Prices in New York City
2002 and 2003

Ratio of DA Price / RT Price

<table>
<thead>
<tr>
<th>Location</th>
<th>2002</th>
<th>2003</th>
</tr>
</thead>
<tbody>
<tr>
<td>Astoria East</td>
<td>9%</td>
<td>11%</td>
</tr>
<tr>
<td>Astoria West</td>
<td>110%</td>
<td>100%</td>
</tr>
<tr>
<td>Vernon/Greenwood</td>
<td>110%</td>
<td>110%</td>
</tr>
<tr>
<td>Greenwood/Staten Island</td>
<td>110%</td>
<td>110%</td>
</tr>
<tr>
<td>Staten Island</td>
<td>120%</td>
<td>120%</td>
</tr>
<tr>
<td>NYC 345 kv</td>
<td>110%</td>
<td>110%</td>
</tr>
<tr>
<td>East River</td>
<td>110%</td>
<td>110%</td>
</tr>
</tbody>
</table>

Inside the 138 kV

Outside the 138 kV
Figure 27: Day-Ahead Congestion Costs and TCC Payments
2001-2003

- Payments to TCC Holders
- Day-Ahead Congestion Rents

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

- No RT Mitigation
- RT Mitigation Invoked

Intervals possibly warranting mitigation

<table>
<thead>
<tr>
<th>Percentage of Intervals</th>
<th>Staten Island</th>
<th>345kV</th>
<th>Astoria East</th>
<th>Astoria West</th>
<th>Vernon/Greenwood</th>
<th>Greenwood/Staten Island</th>
</tr>
</thead>
<tbody>
<tr>
<td>Outside the 138kV</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sub-pockets inside the 138kV</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
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)

Source: PJM State of Markets 2003
## 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>
</tr>
</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>
</tr>
<tr>
<td>2002</td>
<td>$27,626</td>
<td>$57,146</td>
<td>$11,601</td>
<td>$3,915</td>
<td>$43,142</td>
<td>$72,664</td>
<td>1,383</td>
<td>3,203</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>
</tr>
<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>
</tbody>
</table>

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

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

- w/o GT Fuel Adder
- 10 Minute Revenue
- Energy Revenue
- UCAP Revenue

Net Revenue reduction due to higher intraday gas costs
Net Revenue reduction due to higher intraday gas costs

Capital Zone

West Zone
<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>Congestion Costs ($)</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