WHY CAPACITY OBLIGATIONS AND CAPACITY MARKETS?

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DO COMPETITIVE ELECTRICITY MARKETS LEAD TO UNDER-INVESTMENT IN GENERATING CAPACITY?

• Growing concern among policymakers in the U.S. and Europe --- concerned about high prices and blackouts
• Investment in new generating capacity has slowed considerably in the U.S., Canada and the UK
• Growing number of plants have announced intention to close down
• Growing electricity demand and forecasts of pending shortages absent significant capacity additions
• Investment community argues that competitive markets yield too little revenue with too much volatility to stimulate “adequate” investment in generation
• Pressures for changes in market rules: long-term contracts, capacity obligations, supplementary capacity payments
• Changes (at least in the Northeast) need to be compatible with
  – retail competition
  – locational cost variations
  – market power mitigation
ARE INVESTMENT INCENTIVES A PROBLEM IN THE U.S.?

- There is excess generating capacity in many regions of the U.S. at the present time
  - With capacity significantly in excess of optimal reserve margins, prices and “rents” to cover capital costs should be very low
  - Excess exuberance during boom/bubble led to too much investment
  - Increases in natural gas prices have undermined economics of CCGTs
  - One view is “that’s life in competitive markets”
  - Also, investors in existing generating capacity have incentives to lobby for additional sources of revenue
  - But empirical evidence indicates that there really is a problem in the organized Eastern markets despite investment experience during the “bubble”
<table>
<thead>
<tr>
<th>YEAR</th>
<th>CAPACITY ADDED (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1997</td>
<td>4,000</td>
</tr>
<tr>
<td>1998</td>
<td>6,500</td>
</tr>
<tr>
<td>1999</td>
<td>10,500</td>
</tr>
<tr>
<td>2000</td>
<td>23,500</td>
</tr>
<tr>
<td>2001</td>
<td>48,000</td>
</tr>
<tr>
<td>2002</td>
<td>55,000</td>
</tr>
<tr>
<td>2003</td>
<td>50,000</td>
</tr>
<tr>
<td>2004</td>
<td>20,000</td>
</tr>
<tr>
<td></td>
<td>217,500</td>
</tr>
</tbody>
</table>

Source: EIA
<table>
<thead>
<tr>
<th>Region</th>
<th>Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>ISO-NE</td>
<td>3 Mw</td>
</tr>
<tr>
<td>NY-ISO</td>
<td>3,700 Mw (3,200 NYC)</td>
</tr>
<tr>
<td>PJM (traditional/APS)</td>
<td>1,800 Mw</td>
</tr>
<tr>
<td>ERCOT (Texas)</td>
<td>785 Mw</td>
</tr>
<tr>
<td>CA-ISO</td>
<td>4,500 Mw</td>
</tr>
</tbody>
</table>

Source: Argus
IDEALIZED “PEAK PERIOD” WHOLESALE MARKET PRICE PATTERNS

$100

$15,000

$10,000

$2000

$100

Operating reserve surplus

OP-4 Reserve Deficient

Load shedding/demand rationing


Price Cap = $1000/Mwh

$/Mwh

$100 < V_i \leq V_i

V_i(q = (K - r_L))

K/(1 + r_H)

K/(1 + r_L)

\( c_p \)

LONG RUN EQUILIBRIUM “PEAKER” INVESTMENT CONDITIONS (simplified)

Investment:

\[ C_k = \Sigma (p_i - c) = E(w_i) + E(v_i) \]

Marginal cost of peaker = expected marginal net revenue (rent)

Demand/supply balance during “scarcity” conditions:

\[ p_j = w_j(q_j, X_j, r_j, K) \] [operating reserve deficiency]
\[ p_i = v_i(q_i, X_i, r_L, K) \] [load shedding]

An optimal level of capacity \( K^* \) and associate “planned Reserve Margin” \( R = K - E(q_p) \) is implied by the above relationships and the probability distribution of peak demand realizations and generating unit availability.
### SCARCITY RENTS PRODUCED DURING OP-4 CONDITIONS ($1000 Price Cap) ($/Mw-Year)

<table>
<thead>
<tr>
<th>YEAR</th>
<th>ENERGY OPERATING RESERVES</th>
<th>OP-4 HOURS/ (Price Cap Hit)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>MC=50</td>
<td>MC=100</td>
</tr>
<tr>
<td>2002</td>
<td>$ 5,070</td>
<td>$ 4,153</td>
</tr>
<tr>
<td>2001</td>
<td>$15,818</td>
<td>$14,147</td>
</tr>
<tr>
<td>2000</td>
<td>$ 6,528</td>
<td>$ 4,241</td>
</tr>
<tr>
<td>1999</td>
<td>$18,874</td>
<td>$14,741</td>
</tr>
<tr>
<td>Mean</td>
<td>$11,573</td>
<td>$ 9,574</td>
</tr>
</tbody>
</table>

Peaker Fixed-Cost Target: $60,000 - $70,000/Mw-year
Table 2-31 - New entrant gas-fired combustion turbine plant (Dollars per installed MW-year): Theoretical net revenue for calendar years 1999 to 2004

<table>
<thead>
<tr>
<th>Year</th>
<th>Energy</th>
<th>Capacity</th>
<th>Spin</th>
<th>Regulation</th>
<th>Reactive</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>1999</td>
<td>$62,065</td>
<td>$16,677</td>
<td>$0</td>
<td>$0</td>
<td>$2,390</td>
<td>$81,131</td>
</tr>
<tr>
<td>2000</td>
<td>$16,476</td>
<td>$20,200</td>
<td>$0</td>
<td>$0</td>
<td>$2,390</td>
<td>$39,066</td>
</tr>
<tr>
<td>2001</td>
<td>$39,269</td>
<td>$30,960</td>
<td>$0</td>
<td>$0</td>
<td>$2,390</td>
<td>$72,619</td>
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<tr>
<td>2002</td>
<td>$23,232</td>
<td>$11,516</td>
<td>$0</td>
<td>$0</td>
<td>$2,390</td>
<td>$37,139</td>
</tr>
<tr>
<td>2003</td>
<td>$12,154</td>
<td>$5,554</td>
<td>$0</td>
<td>$0</td>
<td>$2,390</td>
<td>$20,099</td>
</tr>
<tr>
<td>2004</td>
<td>$8,063</td>
<td>$5,376</td>
<td>$0</td>
<td>$0</td>
<td>$2,390</td>
<td>$15,829</td>
</tr>
</tbody>
</table>

Average: $26,876 $15,047 $2,390 $44,313

Annualized 20 Year Fixed Cost: $72,000

Source: PJM State of the Market Report 2004
Figure 2-6 - Average monthly load-weighted markup indices: Calendar year 2004

Source: PJM State of the Market Report 2004
Estimated Net Revenue in the New York Market
2002 to 2004

WHY DON’T “ENERGY-ONLY” MARKETS PROVIDE ADEQUATE PRICE SIGNALS?

• Several factors “truncate” the upper tail of the distribution of spot energy prices
  – Price caps and other market power mitigation mechanisms
    • Where did $1000/Mwh come from?
  – Prices are too low during operating reserve deficiency conditions for a variety of challenging implementation problems
  – Administrative rationing of scarcity rather than demand/price rationing of scarcity depresses prices
  – “Reliability” actions ahead of market price response keep prices low
  – SO dispatch decisions that are not properly reflected in market prices (OOM; too few “products” to manage the network?)

• Consumer valuations may be inconsistent with traditional reliability criteria
  – The implicit value of lost load associated with one-day of a single firm load curtailment event in ten-year criterion is very high and inconsistent with reliability of the distribution system (NPCC ~ $300,000/Mwh)
  – Administrative rationing increases the cost of outages to consumers
Price Duration Curves in Highest 5% of Hours
New York State Average Real-Time Price

Source: NYISO (2005)
Frequency of Real-Time Constraints and Mitigation
New York City Load Pockets in 2004

Source: NYISO (2005)
Figure 12 - Day-Ahead and Real-Time Spark Spreads for a Gas-Fired Unit with an 8MMBtu/MWh Heat Rate, January 12 - January 19, 2004

1/14/2004, HE 6 PM, $750

New gas operating day begins 1/15, 10 AM

New gas operating day begins 1/16, 10 AM

Day Ahead - Real Time
Figure 30 - Supply Stack for 1 SPD Run, January 15, Hour Ending 7 p.m.

Market price without OOM

Source: ISO NE
Figure 29 - Supply Stack for 1 SPD run, January 15, Hour Ending 2:00 p.m.

The Marginal Unit Setting Price

Without OOM

Marginal Cost

557.5 MW
51 MW
2,089.40 MW
13,030.30 MW

Self Scheduled MWh's  OOM Gas MWh's  OOM Other MWh's  $0 Bids  Other bids
### Table 30 – Demand Response Program Enrollments, August 1, 2004

<table>
<thead>
<tr>
<th>Zone</th>
<th>No. of Assets</th>
<th>Ready to Respond Assets (MW)</th>
<th>Approved Assets (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>RT Price Response</td>
<td>Demand Response 30 min.</td>
</tr>
<tr>
<td>CT</td>
<td>126</td>
<td>30.7</td>
<td>145.8</td>
</tr>
<tr>
<td>ME</td>
<td>5</td>
<td>1.5</td>
<td>0.0</td>
</tr>
<tr>
<td>NEMA</td>
<td>117</td>
<td>39.4</td>
<td>3.3</td>
</tr>
<tr>
<td>NH</td>
<td>2</td>
<td>0.2</td>
<td>0.4</td>
</tr>
<tr>
<td>RI</td>
<td>12</td>
<td>3.0</td>
<td>0.0</td>
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<tr>
<td>SEMA</td>
<td>83</td>
<td>8.5</td>
<td>0.5</td>
</tr>
<tr>
<td>VT</td>
<td>17</td>
<td>7.5</td>
<td>0.1</td>
</tr>
<tr>
<td>WCMA</td>
<td>99</td>
<td>12.7</td>
<td>2.2</td>
</tr>
<tr>
<td>Total</td>
<td>461</td>
<td>103.4</td>
<td>152.3</td>
</tr>
</tbody>
</table>

Source: ISO New England
EASTERN ISOs ANTICIPATED THIS PROBLEM

- Market designs included capacity obligations that required LSEs to acquire capacity equal to ~ 1.18 of peak load
- PJM (but not NE or NY) applied transmission “deliverability” criteria to generators seeking to be “capacity resources”
- Capacity trading/credit markets have been introduced to allocate capacity and determine capacity prices
- Capacity prices are supposed to provide a market-clearing “safety valve” for imperfections in energy and operating reserve markets (see Joskow-Tirole 2004)
- Investors argue these features are inadequate:
  - Prices are too volatile
  - Price caps on capacity prices (deficiency charges) as well
  - Locational considerations are not adequately reflected
- Other problems have emerged:
  - Market power problems in capacity as well as energy markets
  - Payments for capacity that is not available at peak
  - Capacity prices not properly reflected in spot prices further undermining demand-side responses
INITIAL CAPACITY MARKET DESIGN

$P_k = C_K \times N$

- $C_K =$ annualized capital cost of peaker
- $P_k =$ deficiency charge
- $K^* =$ target system capacity included reserve margin = $1.18D_p$
- $D_p =$ forecast peak demand
- $N =$ capital cost multiplier (1,2,3)
Figure 4-9 - The PJM Capacity Market’s net excess vs. capacity credit market-clearing prices: January 2000 to December 2004
WHAT TO DO?

• Continue to improve the performance of the spot market for energy and operating reserves
  – Raise the price caps to reflect reasonable estimates of VOLL
  – Allow prices to rise faster and higher under OP4 conditions
  – Minimize use of OOM or define a wider array of wholesale market products that are fully integrated with markets for related products (e.g. NE Forward reserve market)
  – Continue efforts to bring active demand side into the spot market for energy and reserves
  – Re-evaluate reliability criteria to better reflect consumer valuations
WHAT TO DO?

- Implement “capacity price” or “capacity obligation” mechanisms as a “safety valve” to produce adequate levels to support investment consistent with reliability criteria
  - “safety valve,” not be a permanent major source of net revenues
  - Consistent with continued evolution of spot wholesale markets and demand side participation
  - Capacity values (peaker rents) should be low when actual capacity is greater than $K^*$
  - Capacity values (peaker rents) should be high when actual capacity is significantly less than $K^*$
  - On average (expected value) capacity price should work out to the cost of a peaker $C_k$.
  - Smoothing around $K^*$ makes sense since there is reliability value when $K > K^*$
  - Capacity payment target should net out peaker scarcity rents that are produced by the spot market ($C_k -$ peaker scarcity rents)
  - Demand side should see a price (payment) consistent with the VOLL that underlies the reserve margin and peaker construction and carrying cost assumptions