Optimization and Risk Management in Open-Access Electric Energy Markets

Joe H. Chow
ECSE, Rensselaer Polytechnic Institute
Troy, NY 12380-12180, USA

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- For more information
  - Web site – www.nyiso.com
Survivor I – Last Episode

Frequency Deviation

IMA 12/4-6/2002

Joe Chow
Topics

- New York deregulated energy market
- Market information structure
- Supplier optimization
- Consumer optimization
- Energy trader optimization
- Grid dispatch and market monitoring
- Research areas
New York Deregulated Energy Market

- Switch to NY Marketplace presentation
New York Electricity Market Expenses

New York Electricity Market Expenses
June to August, 2000–2002

Sources: www.nyiso.com (Summer 2002 Review of the NY Electricity Market, David B. Patton)
Topics

- New York deregulated energy market
- Market information structure
- Supplier optimization
- Consumer optimization
- Energy trader optimization
- Grid dispatch and market monitoring
- Research areas
Market Information Structure (1)

- System forecasted loads and scheduled equipment outages are announced to all MP
- Loads (LSE) bid in hourly forecasted load in the day-ahead market (DAM) – fixed and price-capped
- Suppliers (Generators) bid in minimum generation blocks and incremental energy blocks with increasing costs – the bids not based solely on the generation cost
Market Information Structure (2)

- All supply and demand bids are confidential
- Grid operator (ISO) accepts all supply and demand bids and performs an optimal bid-based unit commitment
- Hourly prices (LBMP, losses, congestions, uplifts) and loads committed for different zones are posted
- Generator dispatch schedules are known only to the individual generator owners
Market Information Structure (3)

- Historical price and dispatch data available from NYISO website
- Masked generator bids posted after 6 months
- Information structure encourages competitive bidding and discourages supplier gaming
- Nevertheless, historical data are useful to optimize bidding
Topics

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- Consumer optimization
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Aggregate Energy Supply and Demand

A Price-feedback Market Simulator

Figure 6.1: The price-feedback market simulator
Supplier Optimization

In a deregulated power market with *uniform* energy clearing prices, there are many generator bidding strategies:

- Nuclear units – price takers, base-loaded, bid negative prices
- Gas turbines – opportunistic, bid high minimum generation and energy prices
- Hydro units – finite stored energy, bid regulation and reserve
- Steam turbines – most likely the price-setters, profits highly dependent on bidding strategies
Typical price ranges


- Nuclear units
- Steam Turbines
- Gas Turbines

High price hours

MCP ($/MWH)

0 50 100 150 200

nuclear units

0 20 40 60 80 100 120

DAM clearing price

Hour of the day
Supplier Optimization

1. Developing bid curves based on generator cost curves
   - Breakeven
   - Maximum profit
2. Bidding with hedging
   - Two-settlement system – accounts for generator availability and derating
3. Block bids
   - Segments for expected maximum profit
4. Unit with limited capacities
   - Pump-hydro unit bidding strategies
Generator Cost Curves

- Quadratic or Cubic functions

\[
C(P) = C_s + C_0 + \beta_1 (P - P_{\text{min}}) + \beta_2 (P - P_{\text{min}})^2
\]

(1)

\[
C(P) = C_s + C_0 + \beta_1 (P - P_{\text{min}}) + \beta_2 (P - P_{\text{min}})^2 + \beta_3 (P - P_{\text{min}})^3
\]

(2)

- \( P_{\text{max}} \) -- maximum generation.
- \( P_{\text{min}} \) -- minimum generation,
- \( C_s \) -- a start-up cost,
- \( C_0 \) -- a “min-gen” cost.

A quadratic cost curve
**Basic Bid Curves— Break-even**

- **Break-even bid curve**

  \[ R(P) = C(P) \]  
  \[ R_{\text{min}} + B(P)(P - P_{\text{min}}) = C_s + C_0 + \beta_1 (P - P_{\text{min}}) + \beta_2 (P - P_{\text{min}})^2 \]  

  Denoting \( P_c = P - P_{\text{min}} \) and assume that \( R_{\text{min}} = C_s + C_0 \)  

  Block-power bid  
  \[ B_{BE}(P) = \beta_1 + \beta_2 P_c \]  

  Break-even bid curve  
  B(P) -- the bid curve as a function of the generation level \( P \).
Basic Bid Curves—Maximum Profit

- Maximum Profit (MP) bid curve

\[
\frac{d\pi_{MP}(P)}{dP} = 0
\]

Incremental revenue = Incremental cost

Denoting \( P_c = P - P_{min} \) and assume that \( R_{min} = C_S + C_0 \)

\[
B_{MP}(P) = \frac{dC(P)}{dP} = \beta_1 + 2\beta_2 P_c
\]  

(9)

\[
\pi_{MP}(P) = B_{MP}P_c - (\beta_1 P_c + \beta_2 P_c^2) = \beta_2 P_c^2
\]  

(10)

Profit Revenue Cost of generation
$B(P)$
($$/\text{MWH})$

- **Maximum profit bid curve**
- **Break-even bid curve**

- $\beta_1$
- $P_{\text{min}}$
- $P_{\text{max}}$
- $P$ (MW)
Supplier Optimization

1. Developing bid curves based on cost curves
   - Breakeven
   - Maximum profit

2. Bidding with hedging
   - Two-settlement system – accounts for generator availability and derating

3. Block bids
   - Segments for expected maximum profit

4. Unit with limited capacities
   - Pump-hydro unit bidding strategies
Generator Availability and Derating

- Two-settlement systems for energy
  - Unit commitment performed in the day ahead market (DAM)
  - Generators which fail to supply the committed power/energy in the real time (RT) market need to buy replacement power/energy
  - Risks: The RT energy prices may be significantly higher than that of the DA market

- Solutions
  - Bid in a curve taken this risk into account
  - Virtual trading (virtual bidding)
Generator Derating

- **Generator Derating** - a unit fails to deliver power at the committed level.
- An extreme case: the whole unit is lost.

Table 1: $p_u$ with respect to $P_c$

<table>
<thead>
<tr>
<th>$p_u$</th>
<th>100 MW</th>
<th>200 MW</th>
<th>300 MW</th>
<th>400 MW</th>
<th>500 MW</th>
<th>600 MW</th>
<th>700 MW</th>
<th>800 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>100 MW</td>
<td>0.005</td>
<td>0.01</td>
<td>0.01</td>
<td>0.01</td>
<td>0.01</td>
<td>0.02</td>
<td>0.03</td>
<td>0.05</td>
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<tr>
<td>200 MW</td>
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<td>0.005</td>
<td>0.01</td>
<td>0.01</td>
<td>0.01</td>
<td>0.01</td>
<td>0.03</td>
<td>0.05</td>
</tr>
<tr>
<td>300 MW</td>
<td>0</td>
<td>0</td>
<td>0.005</td>
<td>0.001</td>
<td>0.001</td>
<td>0.005</td>
<td>0.02</td>
<td>0.01</td>
</tr>
<tr>
<td>400 MW</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.005</td>
<td>0.001</td>
<td>0.005</td>
<td>0.01</td>
<td>0.01</td>
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<tr>
<td>500 MW</td>
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<td>0</td>
<td>0</td>
<td>0.01</td>
<td>0.005</td>
<td>0.005</td>
<td>0.01</td>
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<tr>
<td>600 MW</td>
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<td>0</td>
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<td>0.02</td>
<td>0.005</td>
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<tr>
<td>800 MW</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.05</td>
</tr>
</tbody>
</table>

Availability: 99.5%  98.5%  97.5%  97.4%  97.3%  93.5%  87%   80%
Insurance bid curves

Given the derating probabilities

\[ p_a(P) + \sum_{i=1}^{n} p_u(i) = 1 \]

The expected profit of a unit is

\[
\pi_d(P) = p_a(P)(B_dP_c - (\beta_1 P_c + \beta_2 P_c^2)) + \sum_{i=1}^{n} [p_u(i)(B_dP_c - B_{RT}P_L(i)) - (\beta_1 (P_c - P_L(i)) + \beta_2 (P_c - P_L(i))^2)]
\]
Assume the RT market price $B_{RT}$ is proportional to the DAM price $B_d$

$$k(i) = \frac{B_{RT}(i)}{B_d(i)}$$

$$P_L(i) = k_L(i)P_c$$

A maximization of this expected profit of the unit yields

$$B_d = \frac{\beta_1 + 2\beta_2P_c - \sum_{i=1}^{n}[p_u(i)(\beta_1 k_L(i) - 2\beta_2 k_L^2(i)P_c + 4\beta_2 P_c k_L(i))]}{1 - \sum_{i=1}^{n} p_u(i) k(i) k_L(i)}$$
Let

\[ B_{\text{adj}} = \beta_1 k_L(i) - 2\beta_2 k_L^2(i) P_c + 4\beta_2 P_c k_L(i) \]

\[ k_{\text{adj}}(i) = k_L(i) k(i) \]

A maximization of this expected profit of the unit yields

\[ \frac{B_d}{B_{\text{MP}}} = \frac{1 - p^T \frac{B_{\text{adj}}}{B_{\text{MP}}}}{1 - p^T k_{\text{adj}}} \]
An example of insurance bids

\[ k = \text{Real-time market price} / \text{Day-ahead market price} \]

Table 3: \( k \) with respect to \( P_c \)

<table>
<thead>
<tr>
<th>( k )</th>
<th>100 MW</th>
<th>200 MW</th>
<th>300 MW</th>
<th>400 MW</th>
<th>500 MW</th>
<th>600 MW</th>
<th>700 MW</th>
<th>800 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>100 MW</td>
<td>1</td>
<td>1.2</td>
<td>1.3</td>
<td>1.3</td>
<td>1.3</td>
<td>1.5</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>200 MW</td>
<td>0</td>
<td>1.3</td>
<td>1.4</td>
<td>1.4</td>
<td>1.4</td>
<td>1.6</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>300 MW</td>
<td>0</td>
<td>0</td>
<td>1.5</td>
<td>1.5</td>
<td>1.5</td>
<td>1.6</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>400 MW</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>2</td>
<td>1.6</td>
<td>2</td>
<td>2</td>
<td>3</td>
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<tr>
<td>500 MW</td>
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<td>0</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>3.5</td>
</tr>
</tbody>
</table>
An example of insurance bids

$B_d(P)$ as a function of $k$ and $P$

$B_d(P)$ as a function of $p_u$

If most bidders tend to be risk averse, then under an expectation of RT market price being greater than DA market price, applying insurance bids generally result in a higher MCP price in heavy load area than not taking derating into account.
Supplier Optimization

1. Developing bid curves based on cost curves
   - Breakeven
   - Maximum profit
2. Bidding with hedging
   - Two-settlement system – accounts for generator availability and derating
3. Block bids
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4. Unit with limited capacities
   - Pump-hydro unit bidding strategies
Optimization of Block Bids

- Allowable bid curves
  - Piecewise linear
  - Blocks
- Allowable number of bid curves
  - One per hour
  - One per day
- Multi-segment blocks
  - The goal is to find a set of optimized discretization points (break points) to maximize expected profit
Optimization of Block Bids

If we know the probability distribution function of the market clearing price (MCP):

\[ p_{MCP}(B), \quad \text{for} \quad B_{\min} \leq B \leq B_{\max} \]

The expected profit can be calculated as the sum of three pieces, each having its own dispatch probability:

\[
\pi_B(B_1, B_2) = \int_{B_1}^{B_2} p_{MCP}(B) \left[ B \left( \frac{B_1 - \beta_1}{2\beta_2} - \beta_1 \right) - \frac{B_1 - \beta_1}{2\beta_2} - \beta_2 \left( \frac{B_1 - \beta_1}{2\beta_2} \right)^2 \right] dB
\]

\[ + \int_{B_2}^{B_3} p_{MCP}(B) \left[ B \left( \frac{B_2 - \beta_1}{2\beta_2} - \beta_1 \right) - \frac{B_2 - \beta_1}{2\beta_2} - \beta_2 \left( \frac{B_2 - \beta_1}{2\beta_2} \right)^2 \right] dB \]

\[ + \int_{B_3}^{B_{\max}} p_{MCP}(B) \left[ B(P_{\max} - P_{\min}) - \beta_1 (P_{\max} - P_{\min}) - \beta_2 (P_{\max} - P_{\min})^2 \right] dB \]

Solve for the optimal values of B1 and B2:

\[
\frac{d \pi_B(B)}{dB_1} = 0, \quad \frac{d \pi_B(B)}{dB_2} = 0
\]
An Example of Normal Distribution

B_{\text{min}} = $21$

B_{\text{max}} = $29$

B_1 = $21$

B_2 = $29$
Observations

- The **lower break-point** is bid to ensure that the unit is dispatched with high probability.

- The **higher break-point** is bid at or slightly below the expected MCP.

- The bidding strategy relies on the fact that a unit is most profitable operating on the lower part of the cost curve given a high MCP. Not dispatching under such a circumstance results in lost profit opportunities of maximum profitability.
Supplier Optimization

1. Developing bid curves based on cost curves
   - Breakeven
   - Maximum profit

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   - Pump-hydro unit bidding strategies
Operational Constraints of a Pump-hydro Unit

\[ E_T = E_0 + E_{in} - E_{out} \]

- Inflow Energy: \( E_{in} = P_p t_p \eta \)
- Outflow Energy: \( E_{out} = P_g t_g \)

\[ t_g = \frac{P_p t_p \eta - E_T + E_0}{P_g} \]

- \( E_0 \): Initial Energy stored in the upper reservoir
- \( E_T \): The Energy at the end of an optimization cycle
- \( \eta \): The efficiency of the pumping and generating process
Pump-hydro Unit Bidding Strategies

- Limited water storage capacity

\[
R(P) = R_r + R_g
\]

- Reserve

\[
R_r = P_r (T - t_g) B_r
\]

- Energy

\[
R_g = P_g t_g B_g
\]

\[
\max(\pi) = \max(R_g + R_r - C_0 - C_p)
\]

- Cost

\[
C = C_0 + C_p
\]

- \(C_0\) - a fixed O&M cost

- Pumping water for storage

\[
C_p = P_p t_p B_p
\]
Step 1: Obtain a weekly MCP curve

Figure 1: A weekly MCP curve
Step 2: Form a Weekly Composite MCP Curve

\[ t_g = \frac{P_p t_p \eta - E_T + E_0}{P_g} \]

Figure 2: A weekly composite MCP curve
Step 3: Increase $t_p$ (pumping time), till the optimality condition is reached, where the marginal profit of the pump-hydro unit is zero.
Case 1: Upper Reservoir Capacity not Exceeded

A weekly MCP curve

Optimal Operation schedule
Case 2: Upper Reservoir Capacity Exceeded

A weekly MCP curve

Optimal Operation schedule

No water left!!
Case 2: Upper Reservoir Capacity Exceeded

A weekly MCP curve

Optimization on a daily base in the middle of the week.

Optimal Operation schedule
Case 3. with incomplete information of market clearing prices

Uncertainties in the forecasted prices

The resulting Bp and Bg
Topics

- New York deregulated energy market
- Market information structure
- Supplier optimization
- **Consumer optimization**
- Energy trader optimization
- Grid dispatch and market monitoring
- Research areas
Consumer Optimization

- 2-settlement system: day-ahead load commitment and real time load
- Price-capped load bids
2-Settlement System

- DAM – in day-ahead market, loads bid in to secure supply for their forecasted loads
- RT market – balancing the deficit or surplus in load
- Optimization – minimize total (DA and RT) energy payment
Energy Payment in 2-Settlement System

Price ($/MW)

Total energy payment
\[ = B_{DA} L_{DA} + B_{RT} (L_{RT} - L_{DA}) + \text{Uplift} \]
DAM MCP Estimation

DAM Price ($/MWH)

Load forecast (MWH)

Light load DAM price

Source: www.nyiso.com OASIS.

Heavy load DAM price

Data points: Jan. - Sept. 2002

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DA Load Bids

- Allow the commitment of generators at least 12 hours ahead of actual dispatch
- If not enough loads bid in DAM, ISO dispatches additional generators for reliability, resulting in uneconomic operations. The additional costs pass to consumers as a part of uplift cost.
- *DA load bids need to bid enough load to avoid uplifts, requiring data and suitable strategies to deal with load uncertainties.*
Topics

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- Consumer optimization
- **Energy trader optimization**
- Grid dispatch and market monitoring
- Research areas
Virtual Transactions (1)

- Energy traders – no physical assets (generating plants or physical loads)
- Every trader (with posted collaterals) is allowed to bid supply (generation) or consumption (loads) in DAM. Their DA positions will be reconciled in RT market.
- Virtual transactions increase market liquidity.
- Virtual supply bidders will profit if DA LBMP > RT LBMP; virtual load bidders will profit if DA LBMP < RT LBMP. Require load and price forecast information to be competitive.
Virtual Transactions (2)

- Market rules to deter gaming behavior
- Physical loads can bid with price cap
- Virtual load bidding is by zones – to avoid large load bids on certain buses to cause congestions
- Virtual suppliers pay uplifts – to avoid large supply bids resulting in committing physical generators at minimum generation for reliability concerns
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Grid Dispatch and Market Monitoring (ISO)

- Day-ahead unit commitment – large-scale optimization problem
- Real time dispatch – short-term supplemental optimization with updated load prediction
- Market monitoring and mitigation – prevent gaming behavior; data mining to find unusual dispatch and price patterns
Market Monitoring

- Certain generator owners by their generation location and concentration can dictate prices - market power
- Weaknesses in market rules and computer programs may be exploited by market participants
- To prevent gaming
  - Reference bids
  - Conduct and impact tests
  - Portfolio analysis – overall energy position
  - Rapid price correction if necessary
Topics

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Research Areas

- Data analysis, aggregation, mining, forecasting, ...
- Load and price forecasting - crucial to all bidding strategies
- Supply bidding – risk-minimized bidding, block segment optimization, pump-hydro bidding
- Load bidding – DAM bidding to minimize expected overall energy costs
- Virtual bidding – risk management
- Market monitoring – data mining to find anomalies