Electricity Industry Restructuring and ISO Markets in the US

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POWER INDUSTRY RESTRUCTURING

Competitive Generation

FERC Regulated Transmission

State Regulated Distribution

Customers

SC - Scheduling Coordinator
PX - Power Exchange
ISO - Indep. System Operator
TO - Transmission Owner
LSE - Load Serving Entity
Interconnection Regions

Source: NERC, 2009
<table>
<thead>
<tr>
<th>ISO/RTO</th>
<th>Generation</th>
<th>Transmission</th>
<th>Population</th>
<th>States</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>gigawatts</td>
<td>1000 Miles</td>
<td>millions</td>
<td></td>
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<tr>
<td>CAISO</td>
<td>57</td>
<td>26</td>
<td>30</td>
<td>1</td>
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<tr>
<td>ISO-NE</td>
<td>34</td>
<td>8</td>
<td>14</td>
<td>6</td>
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<tr>
<td>MISO</td>
<td>201</td>
<td>66</td>
<td>53</td>
<td>15</td>
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<tr>
<td>NYISO</td>
<td>41</td>
<td>11</td>
<td>19</td>
<td>1</td>
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<tr>
<td>PJM</td>
<td>165</td>
<td>56</td>
<td>51</td>
<td>13</td>
</tr>
<tr>
<td>SPP</td>
<td>66</td>
<td>51</td>
<td>15</td>
<td>6</td>
</tr>
<tr>
<td>ERCOT</td>
<td>70</td>
<td>40</td>
<td>23</td>
<td>1</td>
</tr>
<tr>
<td>TOTAL</td>
<td>634</td>
<td>256</td>
<td>205</td>
<td>43</td>
</tr>
</tbody>
</table>

Cover 70% of US load
Smart Market Design

• Bid Based (subject to market power mitigation)
• Market clearing respects all technical constraints
• Market clearing is based on optimization software that minimizes “as bid social cost” (max social welfare) subject to technical constraints
• Whole sale prices based on locational marginal price (LMP)
Uniform market clearing prices
Forward Contracting

Residual demand = Total demand – Supply by Others

Price

Marginal Cost

Quantity

Fixed Price Contract Quantity
Market Monitoring and Market Power Mitigation

- Each ISO has a Market Monitoring unit (either internal or external) which is paid for by the ISO but is independent and reports to FERC.

- Functions of the Market Monitoring unit
  - Conducts ongoing empirical analysis of market data
  - Publishes quarterly and annual report on the state of the market
  - Submits opinions to the ISO staff on market design modifications
  - Develops (subject to FERC approval) and implements market mitigation protocols including dynamic screening and mitigation of energy bids, and price caps on various bid components.
  - Monitors participants’ behavior in all ISO markets and files complaints with FERC enforcement division if they detect price manipulation attempts. (in 2013 JPMorgan settled an electricity market manipulation case with FERC for $410 million penalty)
System and Market Operation
Multiple Products and Markets

- Day-ahead energy market
- Real-time energy market
- Forward capacity market
- Financial transmission rights (FTR, CRR) auction market
- Regulation market (capacity and mileage)
- [Flexible Ramping Product]
- Operating reserves markets
  - Spinning
  - Non-spinning
  - Replacement
California ISO Market Timeline

Day Ahead Market (DAM)

- Bids Submitted SIBR (T - 7 days)
- DAM Process Begins (10:00)
- Clear the Market
- Publish Results CMRI (13:00)

Real Time Market (RTM)

- Bids Submitted SIBR (T-1 after 13:00)
- RTM Process Begins (T-75min)
- Clear the Market
- Receive Dispatches ADS
- Settlements MRI-S

Applications:
- SIBR - Scheduling and Infrastructure Business Rules
- CMRI – California ISO Market Results Interface
- ADS – Automated Dispatch System
- SLIC – Scheduling and Logging for ISO of California – Outages
- MRI-S – Market Results Interface-Settlements
Typical Daily Scheduling
Two-settlements Electricity Markets

- The two-settlement electricity markets consist of two interrelated markets: day-ahead (DA) market, and real-time (RT) market.
- DA LMPs are generally considered more stable than RT LMPs.
- The DA market includes three sequential processes: market power mitigation and reliability requirement determination (MPM-RRD), integrated forward market (IFM), and residual unit commitment (RUC).
- In the RT market, the ISO runs the economic dispatch process every 5 minutes to rebalance the residual demand.
- If a resource does not cover its total cost including start-up and minimum load cost through its energy revenue at DA and RT LMPs, its shortfall is covered by an uplift payment which is allocated to market participants.
Unit Commitment Optimization - MIP
(Solved for 24 hours in Day Ahead market)

**Decisions** (financially binding):
on/off, output level and compensated reserves for each unit in each of 24 hours + locational marginal energy prices and reserve prices for each node and hour

**Minimize** \( \sum (\text{fuel cost} + \text{no-load cost} + \text{startup cost}) \)

**s.t.**
- Load balance constraint at each node
- Unit output constrain for each generator
- Unit ramping limits for each gen
- Unit min up time and min down time for each gen
- Transmission constraints (DC approximation with thermal proxy limits)
- Reserves margin requirements
- Contingencies (n-1)

(Cost and constraints data provided as offers in day ahead auction)
Mixed Integer Programming reduced annual operating costs by estimated $23 million.
Power Flow Optimization (every five minutes) and Locational Marginal Pricing (LMP) For Generators that are Running and Synchronized

Decisions:
Price of energy (LMP) at node \( i \) = Marginal cost of energy at the node Calculated as the dual variable to energy balance constraint for the node in a linearized Optimal Power Flow approximation (DCOPF)

\[
\text{Minimize } \sum \text{(Generator Fuel Cost)}
\]
\[
\text{s.t.}
\]
\begin{itemize}
  \item Energy balance (net supply = load at each node)
  \item Generator limits (including dynamic limits such as ramp rates)
  \item Transmission Constraints (AC model with voltage and thermal limits)
  \item Reserve requirements
\end{itemize}

(Cost curves and generator limits data provided as offers in real time auction every 15 minutes)
Congestion Management through LMP

West

Limit = 26 MW

East

80 MW

90 MW

$P_W$

45

40

106

120

$Q_1$

$P_E$

50

45

50

64

$Q_1$

Key:

Prices/Supplies under 26 MW limit

Prices/Supplies with no transmission limit
Over-generation, congestion and no storage capability can lead to negative prices
Example of DA-RT Price Spread
On-peak Balancing Market Prices at ERCOT
January 2002 thru July 2007

Energy Price ($/MWh)

UBES 2/25/03
$523.45

Balancing Energy (UBES) Price

Spot Price Energy- ERCOT SC
Temporal and Locational Hedging
Forward Contracts Mitigate Price Volatility and Market Power
FTR Auction (ERCOT)

q 72 time slices
(24 monthly blocks divided into 3 time blocks)
q Bids (and offers) can cover any subset of the 72 products

q Clearing mechanism maximizes auction revenue subject to simultaneous feasibility test (SFT) in every time slice
q SFT ensures that physical grid could support physical exercise of all outstanding FTRs
Simultaneous Feasibility Guarantees Revenue Adequacy (congestion revenues cover FTR settlements)

\[
\frac{2}{3} G1 + \frac{1}{3} G2 \leq 300 \\
\frac{1}{3} G1 + \frac{2}{3} G2 \leq 220 \\
-100 \leq \frac{1}{3} (G1 - G2) \leq 100
\]

- Two sided FTRs must stay within the outer nomogram
- One sided FTRs (options) must stay within the inner nomogram because we cannot rely on counterflows to alleviate congestion.
LMP + FTRs Supports Renewables Penetration and Sharing of Transmission

$5/MWh when available

LMP set by marginal MW produced

$30/MWh

Thermal unit owns FTRs

LMP=$60/MWh

Without wind, Thermal Gen earns 60-30=$30 per MWh exported over transmission lines and its FTRs offset congestion charges. With wind, Thermal Gen has incentive to let wind maximize output and set LMP to $5/MWh and collect 60-5=$55 per MWh exported over the transmission line for its unused FTRs. Wind can be subsidized by “use it or loose it” FTR awards to offset congestion cost.
Ancillary Services

- **Automatic Generation Control (AGC) – Regulation (Up/Down)**
  - Payment for capacity and performance payment for “mileage” (FERC Order 755)

- **Flexible Ramping**
  - Opportunity cost payment based on energy bid

- **Reserves with varying different response time**
  - Spinning (synchronized) Reserves - Spin
  - Non-spinning (non-synchronized) Reserves
  - Replacement Reserves

- **Voltage Support**

- **Black Start Capability**
Cost Components (California)

Figure 6.7 Ancillary service cost by product

- Regulation down
- Regulation up
- Spin
- Non-spin
- Mileage
- Cost per MWh of load

Total cost ($millions)

Q1  Q2  Q3  Q4  Q1  Q2  Q3  Q4
2012

Cost per MWh of load served ($/MWh)

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Questions?

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