Market Design and Gaming in Competitive Electricity Markets

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OBJECTIVE OF MARKET DESIGN

Develop a set of trading rules and procedures so that when all market participants act selfishly so as to maximize profit while following the rules, the market outcome will replicate the results of a benevolent central planner with perfect information, or a perfectly regulated monopoly.
Alternative Market Structures

**CALIFORNIA**
(before 2001)

- SC
- PX
- ISO
- LSE
- TO

**U. K.**
(before 2001)

- SC
- PX
- ISO
- LSE
- TO

**PJM**

- SC
- PX
- ISO
- LSE
- TO

**NORD POOL**

- SC
- PX
- ISO
- LSE
- TO
The Basic Tradeoffs

- A decentralized electricity market is inherently incomplete. The set of products traded does not capture all the complexities of the system (e.g. ramp rate and reactive power are not priced). Results in suboptimal dispatch and uplifting of non-priced coordination costs, which are susceptible to gaming.

- A centralized market must use multidimensional bidding schemes (e.g. energy, start up costs, ramp rate, inflexibility etc.) and complex market clearing rules. Susceptible to incentive compatibility problems (bidders can game the market by revealing false information).
Market Design Components

Integrated Market Design
Market-Reliability Interface

Energy
- Multiple settlements
- Unit Commitment
- Auction structure

Transmission
- Congestion management
- Property rights
- Hedging

Ancillary services
- Forward markets
- Ensuring supply adequacy
- Demand side participation

Retail Services
- Reliability Differentiation
- Exposure to price volatility
- PBR for distribution companies

Capacity Expansion
- Locational price signals
- Planning Reserves
- Transmission expansion

Market Mitigation
- Monitoring
- Automatic mitigation
- Damage control caps
CONGESTION MANAGEMENT
Transmission Constraints in the Contiguous U.S.

Constraint and constrained flow direction

FERC Division of Market Development, Dec. 19, 2001
Objectives of Congestion Pricing

- Provide incentives to generators to account for transmission constraints in their schedules by direct assignment of congestion cost.
- Provide price signals for efficient redispatch due to transmission constraints
- Create price signals for efficient use of the transmission system
- Create price signals for transmission upgrades
- Prevent gaming due to misallocation of constraints cost
Locational Marginal Prices

Export = Import

With transmission constraint
General Definition of LMP

The LMP is the cheapest cost of delivering one additional MWh to a location while respecting all limits (including contingency limits).

Marginal value of transmission between two locations = LMP difference
Alternative Measures of Congestion Cost and Corresponding Settlements

- Export supply function at location 1
- Avoided cost function at location 2
- Congestion relief cost
- Export quantity
- Incremental cost
- Social cost
- Congestion rent
- Flow limit
- Unconstrained optimal export
- P:
  - P1
  - P2
  - P*
  - E
  - C
  - D

Location 1: Export
Location 2: Import
The case for socialization of congestion relief cost

Price

Congestion social cost

Export supply function at location 1

Congestion relief cost

Avoided cost function at location 2

Constrained flow

Scheduled flow

Quantity

LMP at 2

LMP at 1

Shadow price

On line

Congestion rent
The DEC Game

- Export supply function at location 1
- Avoided cost function at location 2
- Flow limit
- Scheduled flow
- Unconstrained optimal export
- Congestion relief cost
- Redispatch
- Social cost
- Price

P2
P1
P*

A B C D E F

Quantity
ENRON’s “Death Star” strategy

Power play

After California deregulated its energy market, Enron figured out a number of ways to manipulate it. Here is how one of them, code-named “Death Star” by Enron’s energy traders, worked, according to memos released by federal investigators:

1. POWER NEEDED
   A state agency known as the Independent System Operator was responsible for ensuring that California’s residents had power when they needed it. Energy providers would schedule deliveries to meet the needs.

2. ENRON’S SHARE
   Enron, which supplied a share of this power, would intentionally overschedule the amount it knew the system could handle.

3. TOTAL POWER PROMISED
   The state agency, unable to monitor the actual usage and believing that the power grid would be overloaded, then paid Enron to deliver the “excess” electricity somewhere else to avoid congestion. Often that was out of state where it was even harder to track.

4. POWER ENRON WAS PAID TO GET RID OF
   Enron, realizing that it could repeat this pattern, often never had to buy the power that it promised to sell to the agency, increasing its profits even more.

Sources: Robert McCullough, office of State Sen. Joseph Dunn

New York Times Graphic
The DEC Game on Path 26 in California

BEFORE

Generation: 42.9%
Load: 50.3%

ZONE NP15

ZONE SP15

Los Angeles

San Francisco

AFTER

Generation: 42.9%
Load: 50.3%

ZONE NP15

ZONE ZP26

ZONE SP15

Los Angeles

San Francisco
LOAD, GENERATION AND TRANSFERS BETWEEN ERCOT REGIONS ON PEAK SUMMER 2001
SIGNIFICANT CONSTRAINTS
SUMMER 2001

BASED UPON THERMAL LIMITS ONLY
Will Vary Based Upon System Conditions & Generation Dispatch
ERCOT Initial Design

- Zonal markets linked by CSCs (4 zones 4 CSCs)
- QSEs submit balanced bilateral zonal schedules and zonal portfolio balancing energy offers with resource specific premiums
- All schedules accepted. Congestion relieved in two steps
  - Interzonal (CSC) congestion relieved with counterflow from zonal balancing energy offer stack (INCs and DECs).
  - Intrazonal (OC) congestion relieved (if possible) by dispatching local balancing energy resources (redispatched resources paid market clearing premiums if competitive solution exists, otherwise they get OOME payments)
- Counterflow cost initially socialized with two “trigger points”
  - CSC congestion charges and TCRs to be activated 6 months after cumulative counter flow cost reaches $20M over 12 month.
  - Direct assignment of OC congestion cost to be initiated 6 months after cost reaches $20M over 12 month period.
Observed Scheduling Patterns at ERCOT During Aug. 2001

- Consistent overscheduling of generation in the South Zone which resulted in significant resource imbalance credits to QSEs from ERCOT.
- Consistent overscheduling of load in the North Zone which resulted in significant load imbalance credits to QSEs from ERCOT.
Daily Costs for Local Congestion, CSC Congestion, and Total BENA

August 2001

($2,000,000)

($0)

$2,000,000

$4,000,000

$6,000,000

$8,000,000

$10,000,000

$12,000,000

$14,000,000

$18,049,376

$14,486,872

($18,049,376)

($14,486,872)
Findings

• Six QSEs received more than $46 million in LI credits for the 15 day period.
  – August 14 and 15 accounted for 44% of LI credits to the six QSEs.
  – Three of the six QSEs received 91% of LI credits for the 15 day period.

• Eight QSEs received $48 million in RI credits for the 15 day period.
  – August 14 and 15 accounted for 38% of RI credits to the eight QSEs.
  – Three of eight QSEs received 95% of RI credits for the 15 day period.
Epilog

- Interzonal Congestion charges were activated in February 2002
- Interzonal congestion uplift was virtually eliminated and the DEC game between zones was suppressed.
- The PUCT filed suite against the QSEs that collected BENA settlements through over and under scheduling (for protocol violation). An out of Court settlement was reached with several of the QSEs (not including ENRON) who agreed to refund a total of about $25 million dollars. The settlement is pending commission approval.
- Local congestion cost is still socialized and uplift cost is escalating
- New rule will institute a “Texas Nodal” system including direct assignment of all congestion rents by 2006
Uplifted Local Congestion Cost in ERCOT
Pricing Congestion the Right Way

- Charge scheduled transactions the locational price differences between injection and withdrawal point OR

- Charge scheduled transactions a congestion fee that equals to their induced flow on congested lines times the “shadow prices” on these lines

- Pay redispached INCs at import location P2 and sell back energy to DECs at export location P1
Congestion Rent is the Only Incentive Compatible Congestion Charge
ENERGY MARKETS
Economic Withholding by Pivotal Supplier
“Hockey Stick” Bidding in RT Ballanacing Market
ERCOT had to procure 100% of the balancing offer stack during several hours.

Market clearing price was set by 1MW offered on a regular basis at $990 by a QSE that offered the rest of its balancing energy at $200/MW or less.

$17 million changed hands in few hours.

One REP declared bankruptcy.
Price-Setting Bid Curve at ERCOT, 2/25/2003

![Graph showing the bid curve with bid price on the y-axis (ranging from $0 to $1,000) and MW on the x-axis. The graph has points at (0, $149), (50, $149), (100, $990), and (150, $990).]
ERCOT MCPE by Interval, 2/25/2003
Why Mitigate

- Market power cannot be eliminated completely. Because of the nature of electricity some suppliers will have locational market power at some times.
- New entry takes time and while it happens suppliers can extract unacceptable rents.
- Demand inelasticity can result in occasional market failure (markets do not clear or suppliers can name any price they want).
- ISOs are bound by strict rules in acquiring balancing energy and ancillary services that do not allow them to respond to price.
- Demand inelasticity and ISO rigidity enables predatory bidding strategies that are designed to exploit market failure conditions.
Alternative Approaches to Automatic Market Mitigation

- Damage control offer caps
- Exclusion from price setting
- Out of merit (OOM) dispatch and RMR dispatch
- Must offer requirements
- Mitigation of offers based on conduct and impact test of individual bidders (NYISO)
- Mitigation based on market failure tests (bid sufficiency, pivotal bidder, hockey stick) (ERCOT)
Hockey Stick Mitigation in Texas
(Adopted by the PUCT May 2003)

- If balancing bid stack is exhausted, set clearing price based on 95% of offer stack
- Mitigated MCPE = 95% price point \times 1.5
- Offers at prices above mitigated MCPE paid as bid
- Sunshine policy: disclose identity of offerers above $300/MWh (“Sunshine is the best disinfectant”)
Retrospective Impact Analysis of Hockey Stick Mitigation in Texas
July 1, 2002 through March 31, 2003

Bid Curves above $900:
Average 90%, 95% 99% and 100% Points

- Houston Zone
- North Zone
- South Zone
- West Zone

Price ($/MWh)

Portion of stack

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ANCILLARY SERVICES
Ancillary Services

- Automatic Generation Control (AGC)
- Reserves with varying different response time
  - Spinning Reserves
  - Non-spinning Reserves
  - Replacement Reserves
- Voltage Support
- Black Start Capability
Procurement Auction Features

- Key feature - downward substitutability
- Basic Approaches:
  - Sequential auctions (substitution through rebidding)
    - Auction order: Regulation, Spin, Nonspin, Replacement
    - Offer prices: Single, Simultaneous multiple, Sequential
    - Uniform market clearing price in each auction
  - Simultaneous auctions (substitution by ISO)
    - Objective function: Min social cost or Min procurement cost
    - Settlement rules: MCP based on offer type, MCP based on use, Marginal value, Pay as Bid.
    - Pricing to buyers: Marginal cost, MCP based on type
Example

Two type example

- **Regulation**
  - 600 MW at $10 /MW
  - 100 MW at $15 /MW

- **Spin**
  - 200 MW at $5 /MW
  - 300 MW at $20 /MW

\[ d_{RG} = 500 \]

\[ d_{SP} = 500 \]
Sequential Auction

Total Procurement Cost = $15,000

Revealed Social Cost = $10,500
Simultaneous Auction
Minimum Social Cost Selection

Settlement Rule

- Highest Accepted Bid: 16,500
- Marginal Value: 20,000
- Pay as Bid: 10,500 (Soc. Cost)

Procurement Cost ($)

- Misrepresent quality: 16,500
- Incentive compatible: 20,000
- Misrepresent cost: 10,500 (Soc. Cost)
Rational Buyer Auctions
(Min procurement cost)

\[ d_{RG} = 500 \]

\[ d_{SP} = 500 \]

Spin

Regulation

Saves (black): 4500
Spends (red): 2000
Difference: 2500

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1.1. Operating Reserves Market Flaws: TMSR, TMNSR, TMOR.

During June and July the ISO identified design flaws in the operating reserve markets of Ten Minute Spinning Reserve (TMSR), Ten Minute Non-Spinning Reserve (TMNSR), and Thirty Minute Operating Reserve (TMOR). The operating reserve design flaws resulted in markets that are not workably competitive. In a competitive market, higher quality goods should command higher prices. In the operating reserves markets prices did not appear to be reflective of costs and lesser quality reserves received higher prices. For example, Thirty Minute Operating Reserve (“TMOR”) is less useful than Ten Minute Non-Spinning Reserve (“TMNSR”), Ten Minute Spinning Reserve (“TMSR”), or Energy. However, at times, TMOR prices exceeded the prices for all three of the other products.

Price Reversals in California Under Rational Buyer Procurement

- Price reversals have been reported in the CAISO ancillary service market under the rational buyer auction.
- On March 20, 2000 in HE 19, there was a spike in the Replacement Reserve price. The following are published prices for NP15:
  
  **Reg-Up:** $P_1 = 18.44 \$/ MW  
  **Spin:** $P_2 = 35.97 \$/ MW  
  **Non-Spin:** $P_3 = 18.00 \$/ MW  
  **Replacement:** $P_4 = 198.98 \$/ MW  
  
  Note that $P_4 > P_3, P_2, P_1$. Also $P_2 > P_1$.

- A similar pattern in AS prices was observed on Feb 29, 2000 in HE18 when replacement reserve prices were 122\$/ MW.
NP15 A/S Price Reversal Frequency in 2000

If Reg = 4, Spin = 3, Non-spin = 2, Repl. Res = 1, a price reversal occurs if Price\_i > Price\_j for i < j where i,j denote the type of A/S
Price Reversals in ERCOT AS Markets

Under Sequential Auction

Regulation Up
Average Daily Prices

Responsive Reserves
Average Daily Prices

Non Spinning Reserves
Average Daily Prices

Days Between August 1 - September 21

Days between August 1 - September 21, 2001

Days between August 1 - September 21, 2001

Max Price
Min Price
Ave Price

Max Price
Min Price
Ave Price

Max Price
Min Price
Ave Price

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Conclusions

- If gaming is possible it will happen
- Market design must be proactive in anticipating perverse incentives and gaming opportunities
- Structural solutions and incentive mechanisms are preferred but not always possible
- Ex-post market power mitigation too cumbersome and ineffective
- On line ex-ante intervention is needed to mitigate market failure and regulate behavior but distortions should be minimized.