Electricity:Competition and Market

Mohammad H. Rahmati

Sharif University Of Technology

October 12, 2018

Table of Content

Borenstein, et al.. "Measuring market inefficiencies in CA's restructured wholesale elec. mrk." AER (2002), Mercadal, "Dynamic competition & arbitrage in elec. mrk", (2018)

Hortacsu, Puller. "Understanding strategic models of bidding : ERCOT." RAND (2008), Reguant "Complementary bidding & startup costs" Restud (2014)

Introduction

- In the spring of 2000, there were four regions of the United States with independent system operators running spot markets for wholesale electricity
- California, PJM (major parts of Pennsylvania, New Jersey, Maryland,Delaware, Virginia, and the District of Columbia), New England, and New York
- Several other states were to restructure their electricity sector
- Beginning in summer 2000, soaring wholesale electricity prices in California
- The disruptions in California slowed the movement toward restructured electricity markets

Importance and Question

- Aftermath of California's electricity crisis, debates on restructuring and regulator response to the crisis.
- Were soaring power costs the result of market
  - fundamentals such as rising fuel prices, environmental cost, and a scarcity of generating capacity
  - or power suppliers able to exercise significant market power
- This paper estimates each factor: input costs, scarcity, and market power

Dynamic Market Power

- Many papers estimate market power in California, none considering dynamic market power.
- In markets for nonstorable goods (electricity & service) intertemporal market power is crucial
- The problem is exacerbated in electricity because
  - demand is very inelastic in the short run,
  - supply becomes very inelastic as production approaches the system-generation capacity.

Findings

- Luckily, data exist on the hourly output of all generating units and transmission power flows.
- Information collected on their technical characteristics
- Paper findings
  - In summer 2000, wholesale electricity expenditures were $8.98 billion up from $2.04 billion in summer 1999.
  - 21% of this increase was due to production costs
  - 20% to competitive rents
  - 59% to market power

Market Power in Electricity

- During most of the 1990's, regulatory evaluation of short-run horizontal market power was HHI
- Such measures are a poor in the electricity industry
- Because the industry is characterized by
  - highly variable price-inelastic demand
  - significant short-run capacity constraints
  - extremely costly storage.
- In such circumstances, firms with very small market shares could still exercise significant market power.

Model Market Power

- In competitive counterfactural
- Each firm is a price-taker that would sell power from a given plant so long as the price it received was greater than its incremental cost of production.
- Cost of selling a unit in not marginal production costs but opportunity cost from selling in a different market
- A high price in an alternative market can reflect market power in that market, resulting in the transmittal of high prices across markets
- This is only unilateral exercises of market power

Model Market Power

- Collusive attempts to exercise market power
- Many of attributes in electricity facilitate collusion
  - In most electricity markets, firms play repeatedly, interacting on a daily basis, so there is opportunity to develop subtle communication and collusive strategies.
  - The payoff from cheating on a collusive agreement may be limited due to capacity constraints on production
  - the ability to punish defectors may be limited
  - fairly standardized production facilities, so homogeneous costs
- But, this paper focuses on the competitiveness of market outcomes, not modeling collusion.

Estimate Market Power

- Two indicators that distinguish market power
  1. in a competitive market, a firm is unable to take any action, including output decisions or offer prices, that significantly affects the price
     - method of estimation involves studying the bidding and output supply decisions of each firm to detect successful attempts to affect prices
     - Wolak and Patrick (1997), Wolfram (1998), Bohn et al. (1999), Bushnell and Wolak (1999), Wolak (2000), and Puller (2001)
  2. Analyze at the market: whether the market as a whole is setting competitive prices given the production capabilities of all players in the market.
     - less vulnerable to coincidence of a generator, less informative about the specific market power, but it is effective for estimating its scope and severity, as well as identifying how departures from competitive outcomes vary over time

A Comment of the Method

- Drawback of market-level approach: captures all inefficiencies in the market, not due to market power
- For instance, low-cost generators were systematically held out of production simply due to a faulty dispatch algorithm
- For many periods their estimates of marginal costs were equal to prices, so other inefficiencies may play trial role
- Thus the estimates must be taken with the caveat that they include failures to achieve competitive market prices

Consequences of Market Power

- short-run electricity demand: zero price elasticity.
- None of customers are charged real-time retail electricity prices
- Market power varies tremendously on an hourly basis
- In California during the 1998–2001 transition period, end-use consumers were insulated from energy price fluctuations by the Competition Transition Charge (CTC).

Consequences of Market Power

- The CTC was implemented in order to allow the incumbent utilities to recover their stranded generation costs.
- Due to the CTC, end-use consumers faced fixed retail rate schedules during the transition period
- Thus, the CTC greatly lessened even the monthly elasticity of final consumer electricity demand.
- Stranded cost component paid by all consumers was calculated in a way that moved inversely to the energy price: the higher the energy price, the lower the CTC payment for that hour.

Consequences of Market Power

- Due to short-run inelasticity of demand, market power in electricity markets has little effect on consumption quantity
- Notice, a firm exercising market power will restrict its output so that price equal to its marginal revenue
- While other firms that are price-taking will produce units of output for which their marginal cost is virtually equal to price.
- Thus, inefficient production on a market wide basis as more expensive competitive production is substituted for less expensive production owned by firms with market power.
- Wolak, Patrick (1997): higher-cost combined-cycle gas turbine provide baseload

Consequences of Market Power

- In addition, exercise of market power in an electricity network can greatly increase congestion on the network.
- This increased congestion impacts negatively both the efficiency and the reliability of the system
- Electricity prices influence long-term decision-making on generation investment.
- Not efficient if motivated by high prices by market power
- And in other industries of use of electricity

Redistribution Effects

- Market power has potentially large and important redistributional effects
- Utilities filed for bankruptcy
- It is still unclear who will bear what share of the expense,
- How much of the revenues paid to generators will be refunded to buyers under orders from federal regulators.

Power Exchange

- Through December 2000, the two primary market institutions in California were the Power Exchange (PX) and the Independent System Operator (ISO).
- PX ran a day-ahead and day-of market for electrical energy utilizing a double-auction format
- Firms submitted both demand and supply bids
- PX set the market-clearing price and quantity at the intersection of supply/demand curves.

Power Exchange

- PX day-ahead market, firms bid into the PX offers to supply or consume power the following day for any or all of the 24 hourly markets.
- PX markets were effectively financial, rather than physical
- Firms could change their day-ahead PX positions by purchasing or selling electricity in the ISO's real-time electricity spot market.

SC & ISO

- A buyer and seller could make a deal bilaterally.
- All institutions that scheduled transactions in advance, were known as “scheduling coordinators” (SCs)
- Because SCs use the transmission grid to complete some transactions, they are required to submit schedules to the ISO
- The ISO is responsible for coordinating the usage of transmission grid
- ISO responsible for the real-time operation of the electric system

ISO

- ISO ensure that aggregate supply is continuously matched with aggregate demand
- In doing so, ISO operates an "imbalance energy" market (real-time/ spot energy market)
- In this market additional generation is procured in shortfall of supply with double-auction process
- Firms that deviate from their formal schedules are required to purchase (or sell) the amount of their shortfall (or surplus) on the imbalance energy market.
- ISO imbalance energy market constituted less than 5%,PX about 85 %, remainder bilateral trades.

Service

- ISO operates markets capacity/reserve.
- Capacity for unexpected demand peaks & adjust production to relieve congestion on transmission
- Reserves ("ancillary services") are purchased through a series of auctions that determine a uniform price for the capacity of each reserve purchased.
- Capacity is available to provide imbalance energy in real time
- "Regulation reserve" (the most short-term reserve) directly controlled by ISO, second-by-second balance supply and demand,

Market Structure of California Generation

- Appear unconcentrated
- Dominant firms: Pacific Gas & Electric (PG&E) and Southern California Edison (SCE)
- They divested their fossil-fuel generation in 1998
- These divestitures make assets evenly distributed between seven firms.
- The sale was by cover of regulator for the competition.

California ISO Generation Companies (MW)

July 1998—online capacity

Firm	Fossil	Hydro	Nuclear	Renewable
AES	4,071	0	0	0
Duke	2,257	0	0	0
Dynegy	1,999	0	0	0
PG&E	4,004	3,878	2,160	793
Reliant	3,531	0	0	0
SCE	0	1,164	1,720	0
SDG&E	1,550	0	430	0
Other	6,617	5,620	0	4,267

July 1999—online capacity

Firm	Fossil	Hydro	Nuclear	Renewable
AES	4,071	0	0	0
Duke	2,950	0	0	0
Dynegy	2,856	0	0	0
PG&E	580	3,878	2,160	793
Reliant	3,531	0	0	0
SCE	0	1,164	1,720	0
Mirant	3,424	0	0	0
Other	6,617	5,620	430	4,888

California ISO Generation Companies

- PG&E was the largest generation company during the summer of 1998.
- The seemingly dominant position of PG&E is offset to a large extent by its other regulatory agreements.
- All of its nuclear generation is treated under rate agreements that do not depend on market prices.
- More importantly, the incumbent utilities were the buyers of electricity during this time period

Market Power in California's Electricity Market

- Critical to understand interactions between the electricity markets
- Participants moved between markets in order to take advantage of higher (for sellers) or lower (for buyers) prices.
- Attempts to arbitrage the PX/ISO price difference would cause the PX price and ISO imbalance energy price to converge.
- Should analyses the entire market together

Market Power in California's Electricity Market

- Large buyers of electricity directly purchasing from the transmission network: they respond to hourly wholesale prices,
- Utility distribution companies (UDCs) cannot control the level of end-use demand
- Because sellers could move between markets as well, ultimately the buyers had no ability to exercise monopsony power
  - because they could not reduce their hourly demand for energy.

Price Cap and Ancillary Service

- Market integration & impact of price caps in various markets.
- Because the ISO imbalance energy market was the last in a sequence of markets, price cap in there fed back to form an implicit cap in advance markets.
- Aggregate demand curve in the day-ahead PX market became near horizontal at ISO price cap
- Many suppliers are eligible to earn capacity payments for providing ancillary services
- Some generators are physically unable to provide certain ancillary services.
- Ancillary markets less competitive than energy market

Import $ Export

- California ISO region could have to be a net exporter of power.
- During the sample period, such conditions arose in only 17 hours out of the 22,681 hours in the sample.
- Net export opportunities for producers within California were very limited relative to the California market.

Measure Market Power

- Fundamental measure of market power is the margin between price and the marginal cost of the highest cost unit necessary to meet demand.
- Even in a market in which some firms exercise considerable market power, the marginal unit that is operating could have a marginal cost that is equal to the price.
- When a firm reduces output from, its production is replaced by other, more expensive generation
- Therefore must estimate what the system marginal cost of serving a given level of demand would be if all firms were price-takers.

Market-Clearing Prices

- Use unconstrained PX day-ahead energy price as estimate of energy prices in any given hour
- Because represents the market conditions most closely replicated marginal costs
  - no transmission congestion costs
  - no local reliability constraints
- Theoretically may be overstate the marginal cost
  - because sellers include a premium to account for the opportunity of earning ancillary services revenues
  - required that the units not be committed to sell power in a forward market
- Empirically not, PX average price was not significantly greater than the ISO average price.

Market-Clearing Quantity

- Systemwide aggregate demand as the market-clearing quantity PX+other SCs+"imbalance energy"
- ISO allocates imbalance energy charges among SCs using its metered aggregate demand during an ex post settlement process.
- Unlike the other forms of reserve, regulation capacity is, held out of the imbalance energy market
- So, add the upward regulation reserve requirement to the market clearing quantity

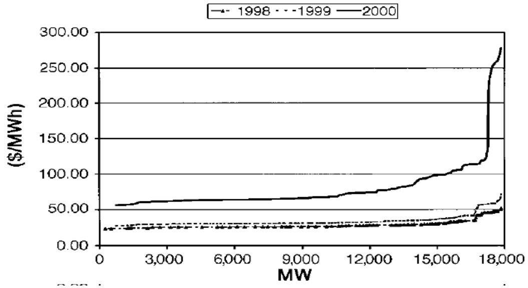
Estimate Marginal Cost

- Divide production into three economic categories: reservoir, must take, fossil-fuel generation.
- Reservoir generation: hydroelectric and geothermal production.
  - face a binding intertemporal constraint on total production
  - implies an opportunity cost of production that generally exceeds the direct production cost
- Must-take generation operates under a regulatory side agreement and is always inframarginal to the market:
  - nuclear, wind, solar

Estimate Marginal Cost

- For fossil-fuel generation: estimate marginal cost using fuel costs and generator efficiency ("heat rate") of each generating + variable operating and maintenance (O&M) cost
- For units under the jurisdiction of the South Coast Air Quality Management District (SCAQMD) in southern California, cost of NOx emissions included
- Emission costs rose sharply in summer 2000
- Next Figure illustrates the aggregate marginal cost curve for fossil-fuel generation
- it increased between 1998 and 2000 due to higher fuel and environmental costs.

California Fossil-Fuel Plants Marginal Cost Curves, September



Estimate Marginal Cost

- Not include any adjustments for "forced outages" (as opposed to scheduled) assumed random
    - constant marginal cost mc_i: unit's average heat rate, fuel price, variable O&M cost
    - maximum output capacity, cap_i
    - forced outage factor fof_i: probability of an unplanned outage in any given hour.
- Because the aggregate marginal cost curve is convex
    - estimating aggregate marginal cost using $cap_i \times (1 - fof_i)$ understates the actual expected cost
    - Use Monte Carlo simulation methods

Estimate Marginal Cost

- If the generation units $i = 1, \cdots, N$ are ordered according to increasing marginal cost
- Aggregate marginal cost curve produced by the j^{th} draw of this simulation, $C_j(q)$, is the marginal cost of the k^{th} cheapest generating unit:

$$k = argmin \left(x \middle| \sum_{i=1}^{x} I(i) \times cap_i \geq q \right)$$

- $I(i) = 1$ with probability of $1 - fof_i$, 0 otherwise

Estimate Marginal Cost

- The marginal cost at a given quantity for each iteration is then the marginal cost of the last available
- If during a given iteration, the fossil-fuel demand exceeded available capacity, the price was set to the maximum allowed under the ISO imbalance energy price cap during that period.
- But this never happened.

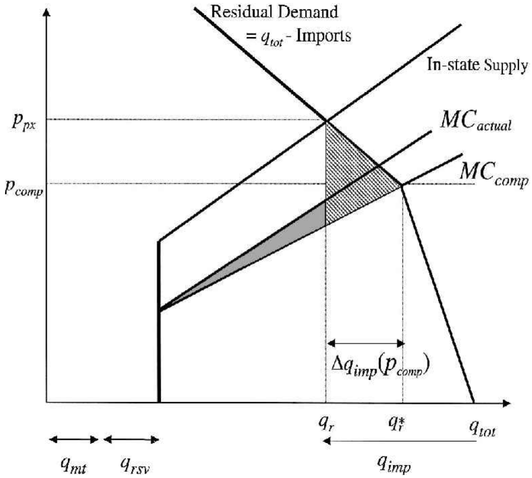
Estimate Marginal Cost

- Wolak and Patrick (1997) present evidence that the timing of such outages was extremely pro table for certain firms in the U.K.
- did not adjust for actual outages, because outages for maintenance is itself a strategic decision.
- Sunk costs (capital costs) and periodic fixed costs should not be included in estimate of short-run marginal cost.
- Commitment costs (starting up a plant): paper does not attempt to capture directly the impacts of these constraints on cost estimates.

Imports and Exports

- One of the most challenging aspects of estimating the marginal cost is accounting for imports and exports
- When market power is exercised within California, allowing more expensive imported power to be substituted for it
- Thus, in the absence of market power, we would see lower imports.
- Next figure: marginal cost curve of the in-state generation, excluding must-take (q_{mt}) and reservoir energy resources (q_{rsv})
- The market demand is q_{tot}, and the observed price is P_{px}, import $q_{imp}(= q_{tot} - q_r)$

Import Adjustments and Efficiency Losses



Imports and Exports

- the price were instead set at the competitive price of P_{comp}
- Imports at some level less than or equal to P_{px}
- Shift the residual in-state demand to a quantity q_r^*.
- Thus, in order to estimate the price-taking outcome in the market, we need to estimate the net import or net export supply function.

Estimating the Net Import/Export Supply Functions

- ISO is to ensure the reliable usage of the system's transmission network.
- Need a market for rationing transmission capacity in oversubscribed times
- Schedule "adjustment" bids: coordinators submit their preferred import or export quantities
- ISO checks to see whether these flows exceed transmission capacity limits.

Estimating the Net Import/Export Supply Functions

- If schedules exceeds, the ISO initiates a process of congestion relief by adjusting schedules according to their adjustment bids.
- Adjustment bids establish, a willingness-to-pay for transmission usage.
- A uniform price for transmission usage, paid by all SCs using the intertie,

Estimating the Net Import/Export Supply Functions

- Adjustment bids reveal the willingness-to import
- Aggregate net flow is usually into California
- import supply curve of sc at import zone z

$$q_z^{sc}(p) = q_z^{sc,init} + \sum_{\hat{p}<p} q_z^{sc,inc}(\hat{p}) - \sum_{\hat{p}>p} q_z^{sc,dec}(\hat{p})$$

- Preferred level of imports from sc at z at a price of p
  - would be its scheduled imports, which are independent of price
  - plus the amount of additional supply it is willing to provide in exchange for receiving a payment
  - less than or equal to p, minus the amount of reduction in supply that it would agree to in exchange for making a payment that is greater than or equal to p.

Estimating the Net Import/Export Supply Functions

- Aggregate import curve

$$q_{imp}(p) = -\sum_{sc}\sum_{z} q_z^{sc}(p)$$

- Upper bound on the responsiveness of net imports to changes in the California price.
- ISO prevented from substituting import adjustment bids across individuals
- So the actual import supply curve is significantly steeper function of price

Hydroelectric and Geothermal Generation

- Reservoir generation units (i.e., hydro, geothermal) reallocate over time
- So do not reflect a production cost but rather the opportunity cost of using the hydro energy at some later time.
- Hydro firm with market power impacts prices in different hours.
- So, actual observed bid prices provide little information about its opportunity cost
- Actual opportunity cost of water for these units will be influenced by the expectation of future prices, and its power to raise them

Hydroelectric and Geothermal Generation

- Assumption: observed output is by a price-taking firm (competitive market)
- Claim: by assumption downward-biased estimates on the efficiency effects of market power.
- The optimal hydro schedule will lead to lower production cost than other hydro schedules.
- If not optimal, it could only raise total production cost.
- Thus the assumption will bias upward our estimate of perfectly competitive production cost.

Hydroelectric and Geothermal Generation

- Concern: observed hydro schedule produces a lower marginal cost estimate (on average) than optimal hydro schedule.
- With convex marginal production costs from nonhydro sources any reallocation of hydro away from least-cost allocation:
  - will raise marginal costs more in the hours from which energy is removed than it will reduce marginal cost in the hours to which energy is added
- Thus optimal hydro production assumption can only bias the time-weighted estimates of marginal cost upwards
- Therefore our estimates of price-cost margins downward.

Hydroelectric and Geothermal Generation

- A hydro market power allocate less hydro energy during peak hours than would be the case for a price-taking firm.
- This strategic hydro allocation + competitive fossil-fuel production, produce a higher weighted average of marginal cost than optimal schedule
- $\Rightarrow$ Results will understate the overall level of market power.
- Majority of reservoir resources were controlled by the PG&E and SCE, with strong incentive to lower wholesale power costs.
- $\Rightarrow$ possible that firms responded with an overconcentration during high-demand periods. (raise off-peak marginal costs more than it would lower on-peak marginal costs)

Hydroelectric and Geothermal Generation

- If reallocation of hydro result in a lower weighted-average marginal cost
- $\Rightarrow$ systematic deviations from a monotonically increasing relationship between demand and estimates of marginal cost
- Estimated a kernel regression of estimated marginal cost (i.e., competitive price) on system demand
- The system marginal cost estimates were monotonically increasing in demand
- $\Rightarrow$ unlikely that assumption (actual schedule of hydro production is cost-minimizing schedule) creates a negative bias on the weighted average estimates of system marginal costs

Calculating Cost Increase Relative to Competitive Outcome

- Assumption: perfectly competitive market price in the California energy markets for each hour of market operation from June 1998 through October 2000
- Residual market demand to be met by in-state fossil-fuel units within the ISO system in hour t, :

$$q^t_{ff}(p) = q^t_{tot} + q^t_{reg} - q^t_{mt} - q^t_{rsv} - q^t_{imp_{act}} - \Delta q^t_{imp}(p)$$

  - q^t_{tot} actual ISO metered generation
  - q^t_{reg} addition to demand (need for capacity regulation reserve)
  - q^t_{mt}must-take generation
  - q^t_{rsv} reservoir generation
  - $q^t_{imp_{act}} - \Delta q^t_{imp}(p)$ imported energy adjusted by the response to market-clearing price

Calculating Cost Increase Relative to Competitive Outcome

- For each hour
  - Estimates 100 fossil-fuel generation marginal cost curve (j draw for outage of each)
  - For each draws compute the intersection of this marginal cost curve with the residual market demand curve $q^t_{ff}(p)$
  - Yields an estimated marginal cost (C^t_j) and an in-state market-clearing quantity q^t_{rj}
  - Then compute an estimate of the expected value of the marginal cost

$$\bar{P}^t_{comp} = \frac{\sum_{j=1}^{100}(C^t_j)}{100}$$

  - It should be $P^t_{PX} \geq \bar{P}^t_{comp}$

Drawback in Calculating Costs

- 1. Marginal cost estimates may exceed actuals, because not consider the dynamic effects of unit commitment constraints (start-up costs, ramping rates, minimum down times)
- Constraints can cause unit shut down, in essence, lower the true marginal cost of operating that plant.
- Of course these same constraints also can create opportunity costs that, at other times, raise the true marginal cost.
- 2. Marginal cost: values submitted to state and federal regulatory agencies under the former regulated regime.
- So, a unit's marginal cost may be slightly higher than the cost level at which it is capable of operating in a market

Drawback in Calculating Costs

- 3. Not control separately for output levels of reliability must-run (RMR) generation
- Some fossil-fuel generation units have been declared must-run for local grid reliability under certain system conditions. (payment separate than market)
- Because of RMR particularly in spring, it is possible that no other fossil-fuel generation was economic
- Under these circumstances, the highest (opportunity) cost units selling in PX is hydro or outof-state coal plants

Drawback in Calculating Costs

- If the estimated MC is above PX for either 1 or 2, then it seems that the most accurate estimate of market power would come from including the "negative market power" outcomes in our calculations.
- However, total start-up costs for the fossil-fuel units in California are about $39 million
  - < 1 % of total fossil fuel generation production costs
  - < 1 % of the market power rents
- Besides those turn on in summer peak demand (fuel) low start-ups
- So, when great market power, no impact of start-ups

Results

- Up to now, calculate competitive price
- For each hour, calculate an arc elasticity using change in import from the change between the competitive and actual price
- Median arc elasticity of import supply for these hours is 0.63
- Added wholesale cost of energy due to non-competitive market (DTC) = difference between PX and competitive × total ISO less must-take

$$\Delta TC^t = [P^t_{PX} - \bar{P}^t_{comp}][q^t_{tot} - q^t_{mt}]$$

Market Performance

- Market Performance

$$MP(\Phi) = \frac{\sum_{t\in\Phi} \Delta TC^t}{\sum_{t\in\Phi} TC^t}$$

- $MP(\Phi)$ is the proportional increased wholesale cost of electricity during all hours in Φ
- Define $\hat{P}^t_{PX}$ observed PX price for hour t

$$MP(\Phi) = \frac{1/Card(\Phi)\sum_{t\in\Phi}[\hat{P}^t_{PX} - \bar{P}^t_{comp}][q^t_{tot} - q^t_{mt}]}{1/Card(\Phi)\sum_{t\in\Phi}\hat{P}^t_{PX}[q^t_{tot} - q^t_{mt}]}$$

- $Card(\Phi)$ number of hours in the set Φ

Market Performance

- If $E(\hat{P}^t_{PX})$ expectation using joint distribution of outage.
- Using law of large numbers:

$$MP(\Phi) = \frac{\sum_{t\in\Phi}[E(\hat{P}^t_{PX}) - \bar{P}^t_{comp}][q^t_{tot} - q^t_{mt}]}{\sum_{t\in\Phi} E(\hat{P}^t_{PX})[q^t_{tot} - q^t_{mt}]}$$

- Next Table: in June 1998 PX price below marginal cost
- But, must-run contracts price payments were above the market price
- $MP(\Phi)$ is equal to 33 %

Actual Price and Estimated Marginal Costs

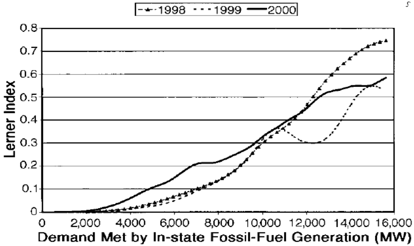
Month	Year	Mean of Actual Production Per Hour (MWh)	Mean of PX Price ($/MWh)	Mean of Marginal Cost ($/MWh)	Sum of ΔTC ($ million)	Aggregate $\Delta TC/TC$ (percent)
June	1998	24,134	12.09	22.55	−44	−51
July	1998	28,503	32.41	27.33	103	28
August	1998	31,256	39.53	27.71	220	39
September	1998	28,209	34.01	26.28	134	33
October	1998	25,043	26.65	26.21	13	5
November	1998	24,107	25.74	27.53	−4	−2
December	1998	24,953	29.13	25.40	45	17
January	1999	24,480	20.96	22.41	−5	−2
February	1999	24,079	19.03	21.20	−12	−7
March	1999	24,734	18.83	20.80	−12	−7
April	1999	24,763	24.05	24.50	4	2
May	1999	24,625	23.61	25.34	0	0
June	1999	27,081	23.52	25.89	13	5
July	1999	29,524	28.92	27.12	63	17
August	1999	29,813	32.31	30.64	56	14
September	1999	28,573	33.91	30.25	63	16
October	1999	27,558	47.63	34.38	186	31
November	1999	26,046	36.91	28.87	105	26
December	1999	26,647	29.66	27.73	30	9
January	2000	26,377	31.18	27.66	48	13
February	2000	25,961	30.04	29.52	10	3
March	2000	25,618	28.80	31.38	−17	−6
April	2000	25,728	26.60	32.43	−43	−16
May	2000	27,038	47.22	40.43	150	25
June	2000	30,644	120.20	53.59	1,152	63
July	2000	30,343	105.72	59.37	801	50
August	2000	32,310	166.24	76.19	1,475	56
September	2000	29,981	114.87	76.86	577	36
October	2000	27,422	101.51	68.06	443	34

Market Power

- Test market power over time
- Expect be low market power during off-peak and abundant supply
- In December 1998–April 1999, $MP(\Phi) = 1.9\%$
- In December 1999–April 2000, $MP(\Phi) = 1.8\%$
- Not significantly different from zero

Rise in Market Power

- One explanation for California electricity crisis: dramatic price increases during the summer of 2000.
- to test one must account for differences in the relative levels of demand during these periods
- Next figure: y-axis $\Delta TC^t/TC^t =$ Lerner index

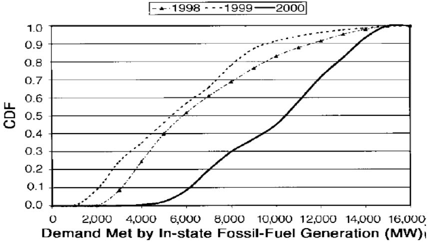


Rise in Market Power

- Figure shows market power steadily increased with the demand faced by fossil-fuel generators.
- In low demand times, no single firm can affect prices
- During higher demand hours, competitive sources reach their capacity limits + inelasticity of demand $\Rightarrow$ high market power
- Under these circumstances, firms find it in their unilateral interest to bid to raise prices even though with sufficient capacity available to meet demand

Crisis and Fossil-fuel Dominance

- Given supply/demand conditions, performance was not dramatically different in 2000 from 1998-99
- Cumulative distribution functions for the demand met by in-state fossil-fuel generation for the late-summer period



- In 2000 fossil demand 6 % higher than 1999, 5% higher in 1998

Crisis and Fossil-fuel Dominance

- Fossil-fuel demands, increased from 6,639 MWh in 1998, 5,690 MWh in 1999 to 10,007 MWh during 2000
- Due to a substantial decline in imports from 5,069MWh in 1998, 6,764MWh in 1999 to 3,627 MWh in 2000
- Although performance controlling for demand faced by fossil-fuel did not change during 2000
- Distribution of this demand did change.
  1. far more hours spent at higher residual demand levels created larger average margins during 2000.
  2. marginal costs also nearly tripled between 1999 and 2000,
- With similar Lerner indices curve, much larger absolute dollar margins, producing extremely large wealth transfers.

Deadweight Loss and Rent Division

- Paper allows to parse the changes in wholesale payments in three categories:
  1. changes in the competitive cost of generating electricity
  2. changes in the level of competitive inframarginal rents (which would have occurred without any market power)
  3. changes in seller rents due to the exercise of market power.
- Rents due to market power in two sub-categories
  1. profits of electricity producers or marketers
  2. some were dissipated in production efficiency losses
- Efficiency losses resulting from the operation of higher-cost production units when a firm with lower-cost production exercises market power and restricts output.

Deadweight Loss

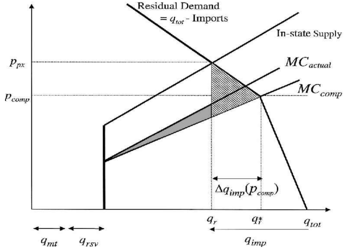
- Efficiency losses from the inefficient allocation of production.
- From the substitution of higher cost production from price-taking firms
- If there were no imports + price inelastic $\Rightarrow$ a straightforward calculation
- Due to imports need to account for substitution of higher-cost imports for lower-cost in-state generation.

Deadweight Loss

- Divide efficiency loss into these two components:loss due to misallocation
  1. of a given production quantity of output among the fossil-fuel plants inside the ISO system
  2. of production between fossil-fuel plants within ISO and plants outside the ISO (imports).
- Assume import bids =marginal cost of the supplier
- Increased impost production due to CA plants' market power creates an increase in total production cost

Deadweight Loss

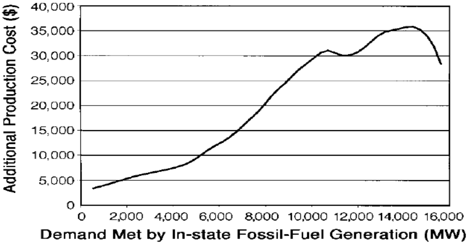
- Inefficiency from reallocation among fossil-fuel inside ISO: solid gray area between competitive marginal cost curve and the "actual" marginal cost curve



- Expected cost from higher than optimal imports is illustrated in the striped area (difference between producing the quantity $\Delta q^t_{imp}(p_{comp})$ from import and producing from in-state production along marginal cost curve MC_{comp})

Deadweight Loss

- Relationship between estimated in-state productive inefficiency and aggregate demand faced by California fossil-fuel



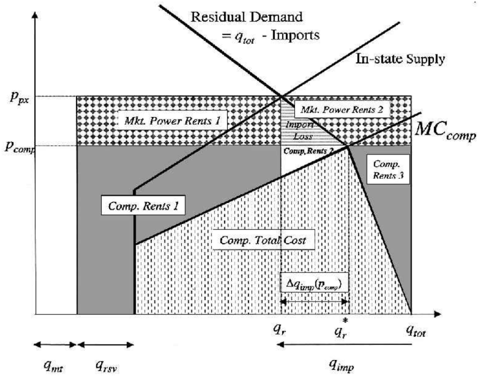
- Low levels of production inefficiency at low levels of system demand, when there are low levels of market power.

Deadweight Loss

- Why does it decreased at very high demand although market power increases?
- At those times small change in production may cause large wealth transfers, the resulting productive inefficiency is small because nearly all resources are running in any case.

Rent Division

- $q_{tot} - q_{mt}$: amount of power traded in the wholesale market
- q_{mt} being must-take power not compensated at market price.
- q_{rsv}: hydro and geothermal production



Rent Division

- Total wholesale market payments are the sum of all the shaded areas.
- Areas labeled "Mkt. Power Rents" and "Import Loss" (together the area above P_{comp}) are removed from the total if market were perfectly competitive.
- Assume that hydro and geothermal power have zero marginal cost (no effect on calculation of change in rents)
- Under competition:
  - q_r^* produced by in-state
  - $q_{tot} - q_r^*$ is imported

Rent Division

- Area labeled "Comp. Total Cost" is the variable production costs (other than must-take production)
- Competition generates rents
  - "Comp. Rents 1 & 2" for in-state fossil-fuel & reservoir generators
  - "Comp. Rents 3" for imports.
- Wholesale market payments: Comp. Rents + Comp. Total Cost

Rent Division-Market Power

- With market power, the quantity q_r is produced by in-state generation & $q_{tot} - q_r$ is imported
- Areas labeled "Comp. Rents 2" and "Import Loss" are the additional variable production costs of the imported power(imports bid competitively)
- In addition to "Comp. Rents 1", in-state producers receive the area "Mkt. Power Rents 1"
- Imports receive "Comp. Rents 3" as well as "Mkt. Power Rents 2"
- Together, these areas account for all wholesale market payments with market power.

Rent Division

- Between the summers of 1998 and 2000, wholesale market cost of power rose from $1.67billionto$8.98 billion.
- Efficient production costs more than tripled between these periods
- Oligopoly rents from about $425millionto$4.44 billion between these summers
- Thus, while a substantial portion of the increased market cost of power was due to rising input costs and reduced imports
  - these factors also increased the dollar magnitude of the market power that was exercised by suppliers.

Rent Division

- Underlying competitive structure of the market does not appear to have changed substantially between 1998 and 2000
- Rather the higher demand and lower import levels in 2000 created more frequent opportunities for in-state fossil fuel producers to collect large margins on increased costs, leading to the tenfold increase in oligopoly rents to suppliers.
- The inefficiencies
  - from the reallocation within California were modest, remaining at about 3–5 % of total production costs in all three summers
  - increased imports in power did grow substantially during our study, rising from 2 % to 8% of total production costs by the summer of 2000

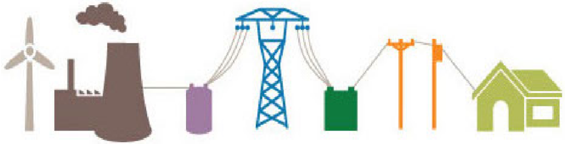
Rent Division

- Underlying competitive structure of the market does not appear to have changed substantially between 1998 and 2000
- Rather the higher demand and lower import levels in 2000 created more frequent opportunities for in-state fossil fuel producers to collect large margins on increased costs, leading to the tenfold increase in oligopoly rents to suppliers.
- The inefficiencies
  - from the reallocation within California were modest, remaining at about 3–5 % of total production costs in all three summers
  - increased imports in power did grow substantially during our study, rising from 2 % to 8% of total production costs by the summer of 2000

Competition and Financial Speculators

- The role of financial speculators is controversial, Commodity markets
- Increase liquidity and informational efficiency.
- Blamed for higher prices in oil, food, electricity.
- Accused of price manipulation in several markets.
  - US Senate investigation: Aluminum, oil, uranium
  - Onion Futures Act (1958)
- This paper: Are financial traders bad for consumers?
- Midwest wholesale electricity market
  1. Physical and financial traders in the same market
  2. Quasi-exogenous variation in financial trading
     - Regulatory change lead to a sharp increase in financial trading.
  3. Detailed dataset on firm behavior
     - Bid data for physical and financial traders

Deregulated wholesale electricity markets



Generation	Transmission	Distribution
Sellers	Market operator	Buyers
Financial sellers	ISO - Independent System Operator	Financial buyers

Wholesale electricity markets: market operation: Sequential market

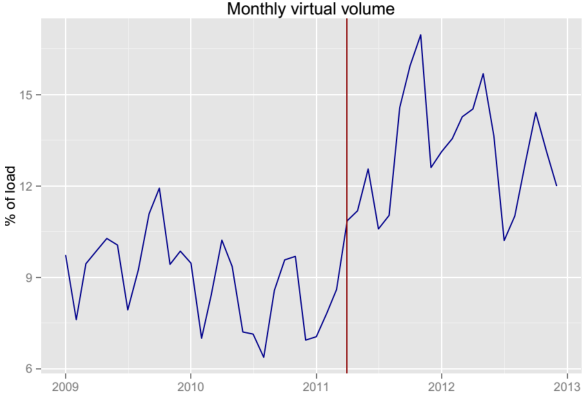
- Timing
  - Forward market: schedules production a day in advance.
  - Spot market: balances demand and supply.
- Physical sellers: Produce electricity
  - Intertemporal price discrimination (Ito and Reguant, 2016)
  - Withhold sales in the forward market, $\Rightarrow$ higher price in forward market
- Financial or virtual traders
  - Compete with physical producers: "virtually" arbitrage.
  - Forward has higher prices $\Rightarrow$ sell in the forward and buy in the spot $\Pi = (PF - PS)Q$

Regulatory change

- Before April, 2011
  - Positive forward premium
  - Trader's supply profits: $\pi = PF - PS - c$
  - Changes c (transaction cost) were as high as the premium $\Rightarrow$ Arbitrage trading was limited
- April, 2011
  - Transaction cost significantly decreased.Expect higher trading, lower forward premium
  - Proposal submitted on December 1, 2010 (Announcement)

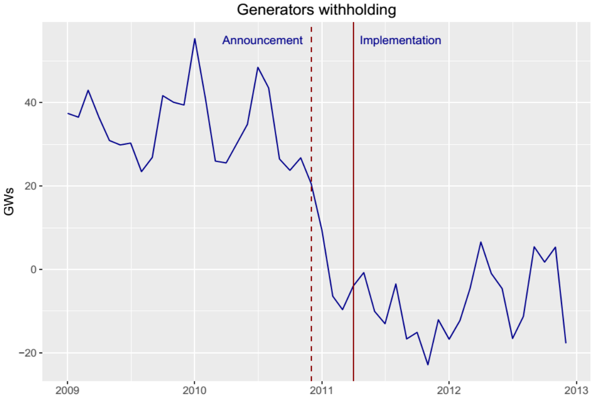
Result 1: Financial trading increased

- Financial traders response to the regulatory change, Breakpoint: April 9, 2011



Result 2: Producers withholding decreased

- Breakpoint: Jan 10, 2011 (1/5, 1/15) before implementation and trader's arbitrage! Why?



Hypotheses: why do generators react earlier?

- Null: Static Nash equilibrium
  - Firms play static best response to the competitive conditions they face.
- Alternative: Dynamic equilibrium
- Do they exert more or less market power than under the static best response?
  1. **Tacit collusion**: they know that collusion is not possible, so break collusion earlier
     behave as if the market were less competitive than static best response
  2. **Entry deterrence**: deter entry of traders by lowering forward premium
     they act as if the market were more competitive than static best response

Static model for a generator

- Static model
- Generator deciding how to bid in a sequential market.
- The optimal forward bid satisfies:

$$\frac{p^F - p^S}{p^F} = \frac{1}{|\eta|}$$

- η is the elasticity of the residual demand faced by the firm.
- p^S is the opportunity cost of selling in the forward market.
- Test of elasticity if a test of n entry deterrence, tacit collusion, and static Nash equilibrium

Test of conduct

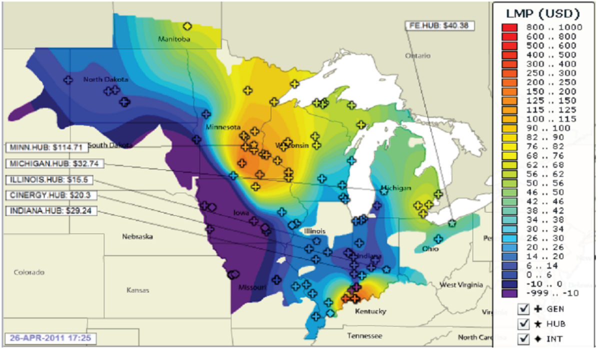
- Define the best response deviation (BRD) as

$$BRD = \frac{p^F - p^S}{p^F} - \frac{1}{|\eta|}$$

- where η is the elasticity of the effective residual demand. Note that:
- BRD $=$
  - $= 0$ Static model holds
  - > 0 Consistent with tacit collusion
    They act as if the residual demand were less elastic
  - < 0 Consistent with entry deterrence
    They act as if the residual demand were more elastic

Challenge: Who competes with whom

- The idea of generators face with residual demand is unclear.
- Not the whole demand when we have transmission congestion

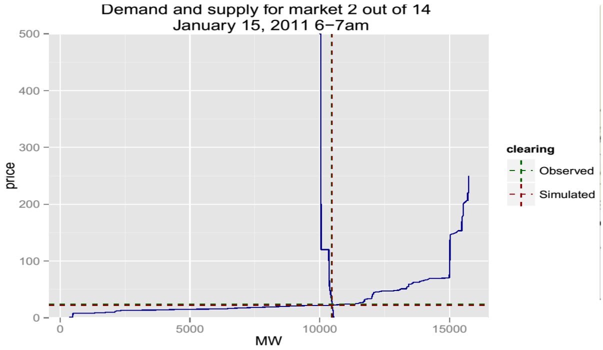


Proposed solution: Split into independent markets

- Idea: prices should move together if firms are in the same market (Stigler and Sherwin, 1985).
- Group firms according to price correlation.
- First paper that studies nodal markets
  - How? Hierarchical clustering (machine learning tool) based on correlation of their prices
- Clustering algorithm requires to specify the number of markets.
  - Use bid data to select best fitting market definitions.
  - Clear each independent market using bids submitted at those locations.
  - Compare simulated and observed prices.

Demand and supply - market clearing

- for a sub-market with 37 buyers, 6 sellers



Test of conduct: Implementation, Best response deviation

- Define Best response deviation of two sides of optimality condition:

$$BRD \equiv \underbrace{p^F - p^S}_{Data} - \underbrace{[\overbrace{Q(p^F)}^{Schedule\,F} - \overbrace{x^F}^{production}]\frac{1}{|R'(p^F)|}}_{Model}$$

- For each hour

$$BRD_{t,m} = \alpha_0 before + \alpha_1 interim + \alpha_2 after + X + \varepsilon_{t,m}$$

- BRD_t: is the average BRD weighted by firm size.
- before: the announcement of the policy change.
- interim: between announcement and implementation.
- after: implementation.
- X: Monthly and hourly fixed effects.

Test of conduct: Implementation, Best response deviation

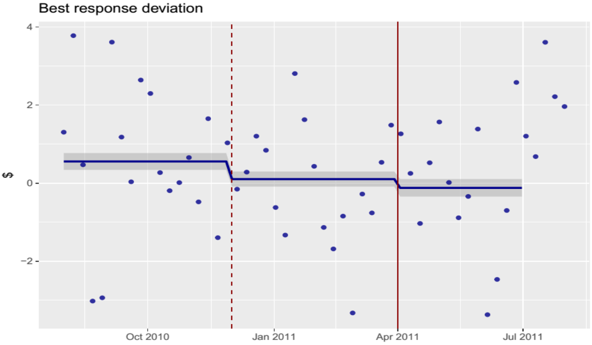
- $BRD = 0$: static model
- If collusive theory: less competitive than it is: $BRD > 0$
- choose a markup larger than what is best given the elasticity of demand they face

$$\frac{p^F - p^S}{p^F} = \frac{Q - x^F}{Q}\frac{1}{\eta}$$

- where Q and η are functions of p^F
- If entry deterrence, firms will act as if the market were more competitive than it actually is
- This means they will choose a smaller markup than the elasticity of their residual demand implies, and $BRD < 0$

Best Response Deviation

- Hourly mean weighted by firm size, month and hour fixed effects.

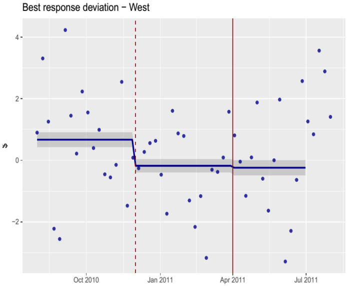


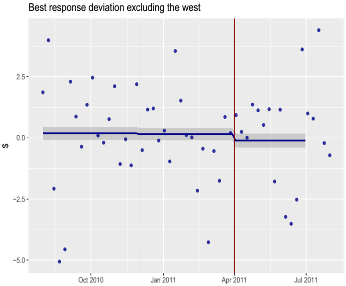
Best Response Deviation

- From announcement generator behaves like as post implementation
- Tacit collusion is unlikely among all firms
- For large firms (mainly located in west) behave as static after announcement

	Main	9 months	Controls	West	No west
	(1)	(2)	(3)	(4)	(5)
Interim	-0.47^{***}	-0.76^{***}	-0.45^{***}	-0.85^{***}	0.02
	(0.15)	(0.15)	(0.15)	(0.16)	(0.18)
After	-0.70^{***}	-0.82^{***}	-0.64^{***}	-0.92^{***}	-0.26
	(0.16)	(0.16)	(0.16)	(0.18)	(0.20)
hhi			-1.88^{**}		
			(0.89)		
Market size			-0.17^{***}		
			(0.03)		
July 2011	2.09^{***}		2.11^{***}	2.39^{***}	1.98^{***}
	(0.24)		(0.24)	(0.26)	(0.37)
Market size×hhi			0.293^{**}		
			(0.14)		
Constant	0.64^{***}	0.58^{***}	1.86^{***}	0.73^{***}	0.21^{*}
	(0.11)	(0.10)	(0.27)	(0.12)	(0.13)
interim = after	Y	Y	Y	Y	Y
after = before	Y	N	N	Y	Y
Observations	37,436	32,421	37,436	30,262	19,719
R^2	0.002	0.001	0.004	0.004	0.002

Best Response Deviation-West vs Non-west





Welfare

- Consumer surplus
  - For a given quantity, consumers pay 4% less.
  - Save about $1,850,000 a day on average in the forward market
- Productive efficiency
  - Forward market: lower costs because of better production scheduling.
  - Spot market: higher costs because generators exert more market power (Ito and Reguant, 2016).
  - Back out spot margins and
    nd they did not increase.

Contribution

1. Role of financial players as competitors of producers
   - Increase consumer surplus.
   - Break tacit collusion.
2. Dynamics matter
   - Test static Nash equilibrium.
   - Reject static Nash in favor of tacit collusion.
3. Machine learning tools can be used to study market structure
   - Obtain competitive structure imposing minimal assumptions.
   - Show it accurately represents the data.

Table of Content

Borenstein, et al.. "Measuring market inefficiencies in CA's restructured wholesale elec. mrk." AER (2002), Mercadal, "Dynamic competition & arbitrage in elec. mrk", (2018)

Hortacsu, Puller. "Understanding strategic models of bidding : ERCOT." RAND (2008), Reguant "Complementary bidding & startup costs" Restud (2014)

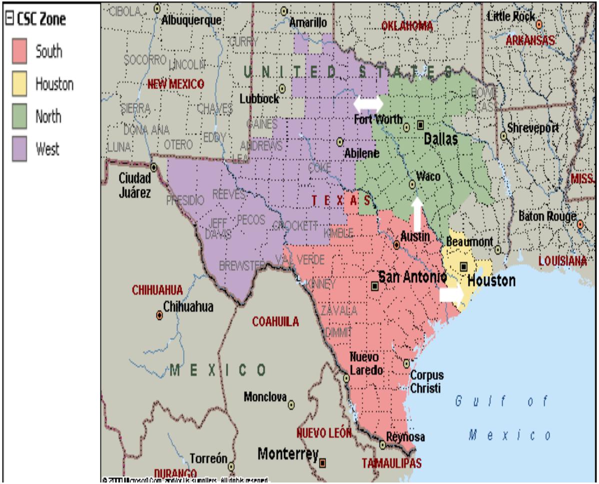
Introduction

- Hortacsu, Puller. "Understanding strategic models of bidding : ERCOT." RAND (2008),
- Empirical oligopoly competition rely on model of firm behavior
- Literature: data on firms prices or bids $\Rightarrow$ estimate costs or object valuation in auctions
- Inferences rely on assumed strategic behavior
- Validity of a particular equilibrium model is left to laboratory

Literature and Paper

- Use marginal cost data to investigate theories of oligopolistic firm behavior:
  - Wolfram (1999),Sweeting (2007) England and Wales electricity market
  - Wolak (2003a) on Australia
  - Borenstein, Bushnell, (2002) & Puller (2007) on California
- This paper
  - Texas, very detailed bidding and marginal cost data
  - Rich cross-section of generation firms
  - Construct benchmarks for each firm's optimal bid functions
  - Compare to actual bids

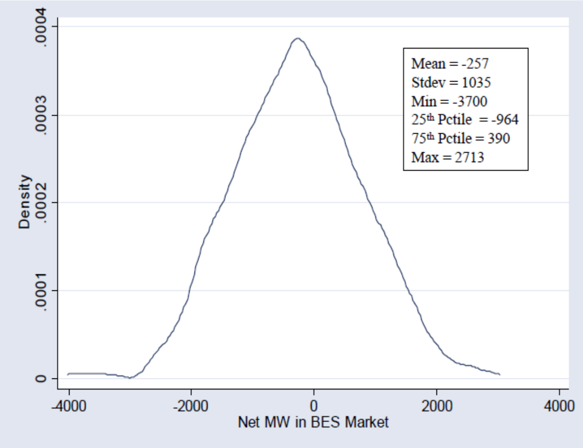
Zones in ERCOT 2002



Bidding in ERCOT Balancing Energy Market

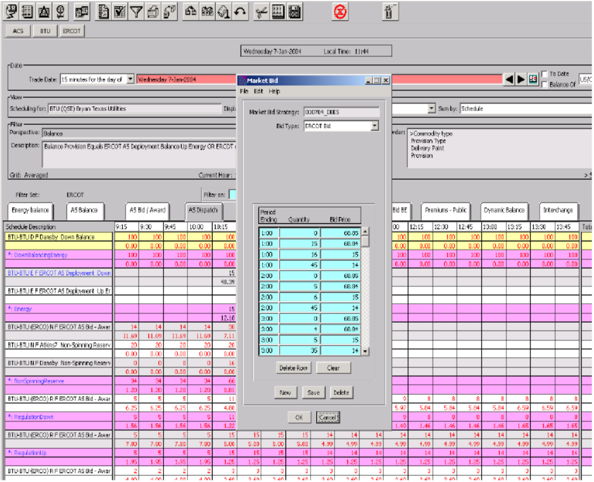
- Spot-market auctions
- Texas: most trades occur via bilateral agreements
- ERCOT: system operator
- 2-5% is traded in "spot market"
- Balancing Energy Services auction, real time
  - One day before, ERCOT accepts schedules of quantities of electricity to inject and withdraw at specific locations on the transmission grid
  - Firms' day-ahead schedules are fixed quantities that do not vary in price
  - Day-ahead schedules may differ from the firms' forward contract position
  - Supply ("generation") & demand ("load") schedules also may differ from actual production

Quantity Traded in Balancing Market

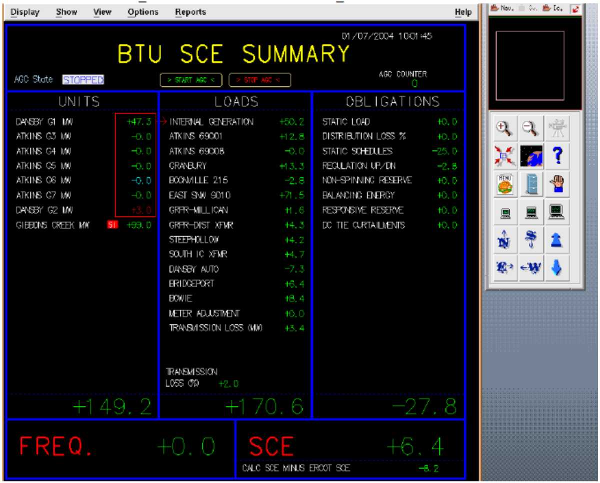


Sample: Sept 2001-July 2002, 6:00-6:15pm, weekdays, no transmission congestion

Sample Bidding Interface



Sample Bidder Operations Interface



Bidding in ERCOT Balancing Energy Market

- Balancing Energy Services auction, real time
  - Balancing market operates in real time to balance actual load and generation
  - Depending whether more or less than day-ahead
  - Balancing demand can be positive or negative
  - As the time nears, ERCOT estimates how much balancing energy is required
  - Balancing demand is perfectly inelastic
  - Bidders offer to increase (INC) and decrease (DEC) the amount of power supplied relative to their day-ahead schedule
  - Firms submit hourly INC and DEC bid schedules that must be increasing monotonic step functions with up to 40 " elbow" points (20 INC and 20 DEC bids)
  - These bids may be changed up until one hour prior to the operating hour
  - 15-minute bid intervals

Bidding in ERCOT Balancing Energy Market

- Uniform-price, multi-unit auction
- ERCOT clears the balancing market
  - four times every hour
  - intersecting the hourly aggregate bid function with 15-minute perfectly inelastic demand function
  - A generator called
    - to INC is paid the market clearing price for all INC sales (production beyond the day-ahead schedule)
    - to DEC pays the market clearing price for the quantity of output reduced
    - she reduces output & purchases power from ERCOT at the market clearing price to satisfy existing contract obligations.
  - Traders know rivals' marginal costs+on/off+efficiency+
  - Similar production technologies
  - No data on competitors' contract obligations

Bidding in ERCOT Balancing Energy Market

- Bilateral contracts are signed in an over-the-counter market
- Difficult to monitor transactions, not publicized
- Wolak (2000, 2003a) these contract affect bidders' incentives to exercise market power
- $\Rightarrow$ very important source of private information
- Residual demand is inelastic total balancing demand minus bids by all other firms
- Total demand is stochastic
    - shocks to total demand (weather) only shift residual demand left and right in a parallel fashion
- Distribution of rival bids inferred in two ways
    1. Compute equilibrium mapping of costs and forward positions to bids
    2. By observing their recent bids with two days lag

Bidding in ERCOT Balancing Energy Market

- Complication of congestion of transmission
- ERCOT geographically divided into several zones
- If not congested b/w zones $\Rightarrow$ balancing a single market
- When congested, ERCOT divides state into separate markets with different market clearing prices
- During congested hours, bids by some firms are feasible while bids by others are not
- $\Rightarrow$ analysis only uncongested hours (74%)
- Focus on 6:00-6:15 pm,flexible type of generators that can respond to balancing calls without large adjustment costs
- Likely to be online during this peak hour of the day
- Average megawatts (MW) traded 915 MW
- Interquartile is from -709 MW to +615 MW

Bidding in ERCOT Balancing Energy Market

- Variety of investor-owned utilities
- Independent power producers, municipal utilities, power cooperatives
- Two largest players are two large former incumbent utilities: TXU (24%) & Reliant (18%)
- Investor-owned utilities: Central Power and Light (7%), West Texas Utilities (2%).
- Municipal utilities: City of San Antonio Public Service (8%), City of Austin (6%))
- Power cooperatives: Lower Colorado River Authority (4%))
- Merchant generation: Calpine (5%)
- Primarily natural gas & coal

Model of Bidding in ERCOT

- Model of strategic behavior
- Uniform price share auction Wilson (1979)
- Firms sign forward contracts QC_{it}, price PC_{it}
- Written a long enough time ago
- "Sunk" decisions to bidders
- Then bid all electricity through auction
- Assume no dayahead scheduling
- Costs of generation $\{C_{it}(q), i = 1, \cdots, N\}$
- Total demand $\tilde{D}_t(p) = D_t(p) + \varepsilon_t$
- Demand: sum of a deterministic price elastic component and a stochastic constant term

Model of Bidding in ERCOT

- Firm simultaneously submits a supply schedule, $S_{it}(p, QC_{it})$
- Auctioneer computes market clearing price, p_t^c

$$\sum_{t=1}^{N} S_{it}(p_t^c, Q_{it}) = \tilde{D}_t(p_t^c)$$

- Firms paid $S_{it}(p_t^c, Q_{it})p_t^c$

$$\pi_{it} = S_{it}(p_t^c, Q_{it})p_t^c - C_{it}(S_{it}(p_t^c)) - (p_t^c - PC_{it})QC_{it}$$

- Payoff from its contract position is $-(p_t^c - PC_{it})QC_{it}$
- Because it has to refund its customers any differential between contract and market prices for contracted sales

Model of Bidding in ERCOT

- Uncertainty in the profit p_t^c
- Two factors: uncertainty in market demand $\tilde{D}_t$,unobserved components $\{(QC_{jt}, PC_{jt}), j \in -i\}$
- Costs are known
- Bayesian-Nash equilibrium
- Strategies are of the form $S_{it}(p, QC_{it})$
- Define probability measure over realizations of market clearing price

$$H_{it}(p, \hat{S}_{it}(p); QC_{it}) \equiv Pr(p_t^c \leq p | QC_{it}, \hat{S}_{it}(p))$$

- Firm i submits supply schedule $\hat{S}_{it}(p)$

Model of Bidding in ERCOT

- Utilizing market clearing price

$$
\begin{aligned}
H_{it}(p, \hat{S}_{it}(p); QC_{it}) &= Pr\left(\sum_{j\in -i} S_{jt}(p, Q_{jt}) + \hat{S}_{it} \geq \tilde{D}_t(p)|Q_{it}, \hat{S}_{it}(p)\right) \\
&= \int_{QC_{it}\times\varepsilon_t} 1\left\{\sum_{j\in -i} S_{jt}(p, Q_{jt}) + \hat{S}_{it} \geq D_t(p) + \varepsilon_t\right\} \\
&\quad dF(QC_{-it}, \varepsilon_t|QC_{it})
\end{aligned}
$$

- $p_t^c \leq p$ equivalent to being excess supply at price p
- $1\{.\}$ indicator for event

Model of Bidding in ERCOT

- Bidder expected utility maximization problem

$$\max_{\hat{S}_{it}(p)} \int_{\underline{p}}^{\overline{p}} U(p\hat{S}_{it}(p) - C_{it}(\hat{S}_{it}(p)) - (p - PC_{it})QC_{it}) dH_{it}(p, \hat{S}_{it}(p); QC_{it})$$

- Euler-Lagrange necessary condition for pointwise optimality of supply schedule $S^*_{it}(p)$

$$p - C'_{it}(S^*_{it}(p)) = (S^*_{it}(p) - QC_{it}) \frac{H_S(p, S^*_{it}(p); QC_{it})}{H_p(p, S^*_{it}(p); QC_{it})}$$

- where

$$\begin{aligned} H_p(p, S^*_{it}(p); QC_{it}) &= \frac{\partial}{\partial p} Pr(p^c_r \leq p | QC_{it}, S^*_{it}(p)) \\ H_S(p, S^*_{it}(p); QC_{it}) &= \frac{\partial}{\partial S} Pr(p^c_r \leq p | QC_{it}, S^*_{it}(p)) \end{aligned}$$

- H_p "density" of market clearing price
- H_S "shift" in probability distribution of market clearing price

Model of Bidding in ERCOT

- Assumption: supply schedules are continuously differentiable
- Reality: firms allowed to bid 40 price-quantity points
- First-order condition as a markup expression
- Markup depends on market power firm
- Firm i shift distribution through its own supply function S
- $H_s \to 0$ no market power + price = mc
- $S^*_{it}(p) < QC_{it}$ firm is a net buyer and bids below marginal cost
- $S^*_{it}(p) - QC_{it} = 0 \quad \Rightarrow \quad p = C'_{it}(S^*_{it}(p))$
- Proposition 1. If $C'_{it}(S^*_{it}(p))$ is observed, one can calculate the contract position QC_{it}, by finding the quantity where the supply function of the firm intersects its marginal cost function

Model of Bidding in ERCOT

- Requires estimation of H_{it}, and its partial derivatives$\forall i, t$
- H_{it} is equilibrium belief of bidder i regarding distribution of market clearing price in auction t, conditional on his bidding strategy
- Estimate of H require strong parametric assumptions on beliefs
- Challenge unobservables entering into beliefs
- Seems impossible
- Equilibrium simplified by functional form of supply function strategies

Model of Bidding in ERCOT

- Proposition 2. If supply function strategies $S_i(p, QC_i)$ are restricted to the class of strategies $S_i(p, QC_i) = \alpha_i(p) + \beta_i(QC_i)$, the markup relation become "inverse-elasticity" $p - C_i'(Si(p, QC_i)) = \frac{S_i(p,QC_i) - QC_i}{-RD_i'(p)}$, where $RD_i'(p)$ is the price derivative of the ex post realization of the residual demand curve faced by bidder i
- Additive separability restriction $\Rightarrow$ residual demand function is additively separable in its random component
- All uncertainty shifts demand curve not rotate it
- Additive separability restriction is testable

Model of Bidding in ERCOT

- Proposition 3. Suppose supply function strategies $S_i(p, QC_i)$ are restricted to the additively separable class of strategies, $S_i(p, QC_i) = \alpha_i(p) + \beta_i(QC_i)$. Then, given data on the marginal cost function, one can compute the ex post optimal supply curve $S_i^{xpo}(p)$, which is the ex post best-response to the observed realization of the residual demand curve.
- So, $RD_i(p, \varepsilon, QC_{-i})$, is enough to compute $\frac{d}{dp} RD_i(p, \varepsilon, QC_{-i}) = RD_i'(p)$ for all realizations.
- Then, for a range of prices, $p \in [\underline{p}, \overline{p}]$, one can solve the equation for S, in terms of p and QC_i
  $\Rightarrow \qquad p - C_i'(S) = \frac{S - Q_i}{-RD_i'(p)}$
- Restrictive assumption allows solve optimal supply schedules
- Importantly, ex post optimality + dealing with unobservables
- No need on how to model role of unobservables.

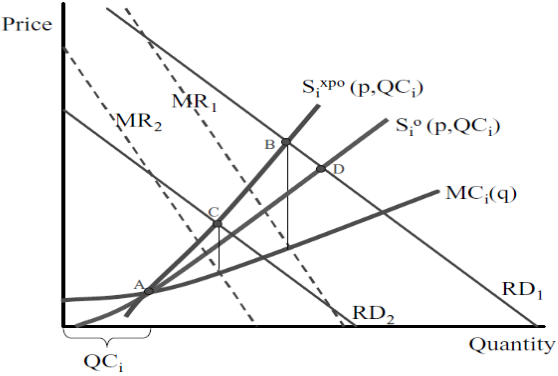
Analysis of Observed Bid Schedules

- Empirical application:
  - Proposition 3
  - marginal cost functions
- To calculate ex post optimal supply curve= equilibrium bid
- Compare ex post optimal bid to actual
- Recall: day ahead market: a fixed-quantity schedule
- Then compete in balancing auction to increase or decrease supply from that day-ahead quantity
- Implementing Proposition 3
  - Quantity committed in day-ahead schedule $\Rightarrow$ shift total marginal cost function to the left by day-ahead quantity
  - Day-ahead quantity to satisfy forward contract positions $\Rightarrow$ any remaining contract position QC_{it} affects bidding into the balancing market

Analysis of Observed Bid Schedules

- Empirical notation:
  - $S_{it}(.)$: supply bids
  - $C_{it}(q)$: costs savings of increasing/reducing output relative to the day-ahead schedule
  - QC_{it}:quantity that the firm is long or short on its contracted sales after day-ahead schedule and upon entering balancing market.
- Measure QC_{it}: by Proposition 1, quantity actual (balancing) bid schedule, $S_i^0(p, QC_i)$ intersects (balancing) marginal cost function (point A in Figure)

Analysis of Observed Bid Schedules



Analysis of Observed Bid Schedules

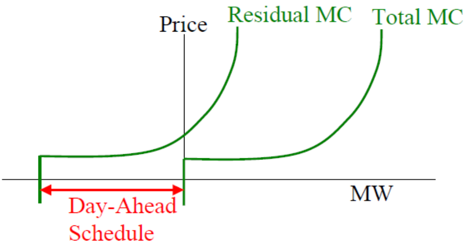
- Residual demand $RD_i(p)$: total demand minus bids by all rival firms
- Suppose RD_1 in Figure is actual realization of residual demand for firm i
- Calculate $RD\prime_1(p)$ and ex post optimal (price, quantity) bid to be point B
- Marginal revenue curve corresponding to $RD_1(p) = MR_1$
- Calculate ex post optimal bid under other possible ε and QC_{-i}
- Say $RD_2 \Rightarrow \quad MR_2 = MC_i(q)$ or point C
- Ex post optimal bid $S_i^{xpo}(p, QC_i)$ tracing out by B, C, $\cdots$ for other RD realization
- Necessary assumption that slope of residual demand is independent of uncertainty

Analysis of Observed Bid Schedules

- Residual demand function is a step function
- $\Rightarrow$ derivatives are either zero or infinity
- Solution
  1. Wolak (2003a, 2003b) to obtain a “smoothed” version of residual demand
  2. Perform grid search on “unsmoothed” residual demand, find ex post profit-maximizing point for each parallel shift in residual demand
- Two solution the same results.

Data

- Hourly data on balancing demand and firm-level bids & marginal costs
- Variable costs: fuel, O&M, SO2 permit costs
- "marginal cost of balancing power": costs of increasing production (INC) or DEC

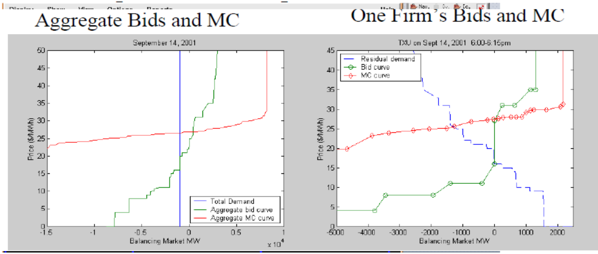


Data

- Total MC: stack up from cheapest to most expensive
- Certain types of generating units that cannot supply power on short notice are then excluded from this MC stack
- Gas & coal adjusted on short notice
- Hour 6:00-7:00 pm hour of each non-congested weekday.

Example of Data We See

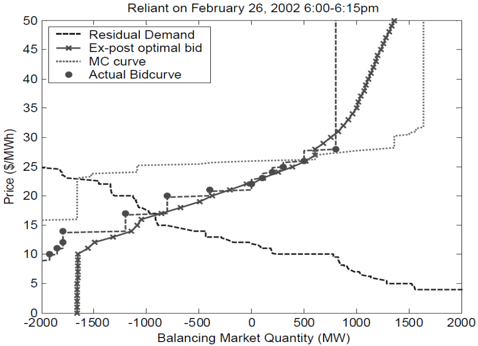
- Sept 14, 2001 6:00-6:15pm
- Total Balancing Demand = -996 MW



Compare Actual Bids to Ex post Optimal Bid

- Large suppliers: Reliant, TXU, Calpine. Small: Guadalupe

Reliant

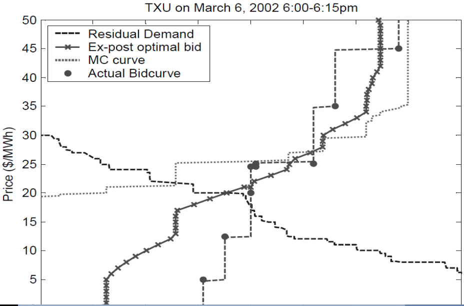


- Reliant's close to optimal bids than to MC
- Competitive bidding: "MC curve"
- Optimal bidding: "ex post optimal bid"

Compare Actual Bids to Ex post Optimal Bid

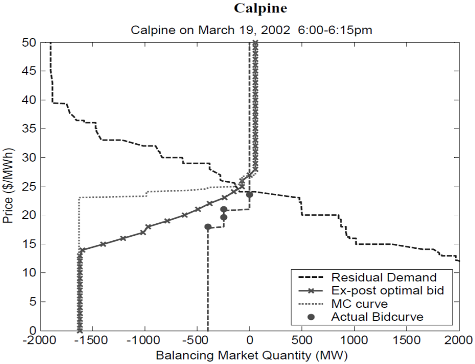
- Intersection of actual bids & MC schedules is contract position
- Quantities above (below) contract position, ex post optimal bid function is above (below) marginal cost
- TXU close to ex post optimal bid on INC (balancing > 0), but bids below ex post optimal prices on DEC side

TXU



Compare Actual Bids to Ex post Optimal Bid

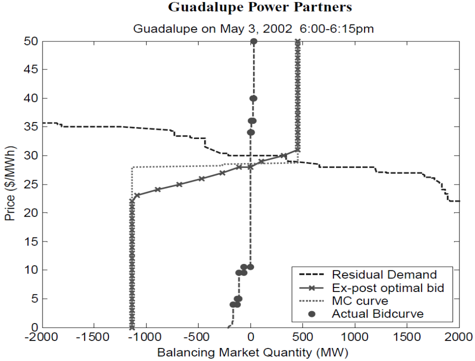
- Calpine offers some DEC bids but not INC



- DEC offers at prices below ex post optimal bids

Compare Actual Bids to Ex post Optimal Bid

- Guadalupe bids much steeper than ex post optimal



- Small seller ⇒ its residual demand is relatively flat
- Bid not for market power, but to avoid being called
- Many small sellers similar bidding patterns

Compare Actual Bids to Ex post Optimal Bid

- Closeness of actual bidding behavior to ex post optimal behavior
- How much profit they have foregone ex post by deviating from the ex post optimal bidding schedule?
- Difference of producer surplus obtained at actual submitted price/quantity point (point D) and surplus obtained at ex post optimal point (point B)
- Calculate this difference in each firm-auction for 20 simulations of residual demand
- Simulation by adding uniformly distributed noise (with support -200 MW to +200 MW) to actual demand

Compare Actual Bids to Ex post Optimal Bid

- Producer surplus relative to "suboptimal" behavior (benchmark)
- Benchmark: behaving nonstrategically, bidding marginal cost
- "default" behavior: avoid being called to supply balancing power
- Smaller firms bid only small quantities
- $\Rightarrow$ Measure performance= fraction of (dollar) distance between "no bidding" and ex post optimal bidding

$$Percent \quad Achieved = \frac{\pi^{Actual} - \pi^{Avoid}}{\pi^{XPO} - \pi^{Avoid}}$$

Compare Actual Bids to Ex post Optimal Bid

- This is just market performance not bilateral transactions
- No data on contract prices
- Construct upper bound for overall profitability
- Upper Bound Total Percent Profitability $=$ Percent Achieved $\times$ %Sales in balancing $+100\% \times$ %Sales in Bilaterals

Outcomes under Alternative bidding

Firm	*Percent Achieved* Relative to XP Optimal (1)	Naive BR (2)	Producer Surplus ($/hour) Actual (3)	Naive BR (4)	XP Optimal (5)	Quantity Sales (MW) XP Optimal (6)	Actual (7)	Upper Bound Total Prof (8)
Reliant	79%	80%	3,422	4,268	4,333	507	431	98%
Brownsville PUB	50%	50%	173	343	343	42	17	88%
City of Bryan	45%	45%	221	488	488	56	30	85%
Tenaska Gateway Partners	41%	41%	456	1,111	1,115	182	72	88%
TXU	39%	41%	1,243	3,056	3,159	441	133	97%
Calpine Corp	37%	38%	820	2,168	2,214	408	102	91%
Denton Municipal Electric	35%	35%	11	31	31	3	1	98%
Ingleside Cogeneration	31%	31%	171	541	541	81	25	79%
City of Austin	30%	31%	581	1,889	1,907	271	48	84%
Rio Nogales LP	28%	28%	109	393	393	60	10	93%
Lower Colorado River Auth	25%	25%	367	1,471	1,488	274	28	88%
City of San Antonio	23%	24%	290	1,221	1,241	266	49	90%
Gregory Power Partners	20%	20%	143	720	722	96	14	82%
Midlothian Energy	17%	17%	171	1,016	1,024	175	15	86%
Cogen Lyondell Inc	16%	16%	408	2,523	2,523	269	34	67%
Tractebel Power Inc	16%	16%	127	795	795	97	15	79%
Brazos Electric Power Coop	15%	15%	101	676	677	82	6	79%
Lamar Power Partners	15%	15%	266	1,800	1,808	272	30	79%
Mirant Wichita Falls	14%	14%	16	114	114	18	2	83%
BP Energy	14%	14%	134	993	994	135	17	80%
City of Garland	13%	13%	128	1,018	1,019	115	5	80%
Hays Energy	8%	8%	64	775	777	111	8	82%
West Texas Utilities	8%	8%	132	1,635	1,635	224	11	82%
Central Power and Light	8%	8%	185	2,375	2,407	352	35	80%
Guadalupe Power Partners	6%	6%	140	2,356	2,380	396	12	77%
Tenaska Frontier Partners	5%	5%	52	1,044	1,051	144	7	80%
South Texas Electric Coop	3%	3%	8	298	298	44	1	81%
Sweeney Cogeneration	2%	2%	10	409	409	46	2	85%
Brazos Valley Energy LP	0%	0%	1	134	134	12	0	68%
AES Deepwater	0%	0%	1	969	969	92	0	60%
Frontera General LP	0%	0%	0	984	1004	197	0	62%
TGC	0%	0%	0	405	405	70	0	81%
South Houston Green Power	0%	0%	0	60	60	7	0	70%
Air Liquide America	−8%	−8%	−181	2,174	2,176	103	9	55%
Extex Laporte LP	−81%	−81%	−1,230	1,497	1,497	92	116	41%

Outcomes under Alternative bidding

- Naive BR is the naive best-response bid to rivals' lagged bids
- XP Optimal is ex post optimal bidding
- Largest firms under ex post optimal bidding
  - producer surplus $2300/hour
- Smaller firms under ex post optimal bidding
  - producer surpluses $750/hour
- Reliant achieves 79% of ex post optimal profits
  - $3,422/hour of $4,333/hour of potential profits

Outcomes under Alternative bidding

- Why under performing?
  - Actual bid functions tend to be “too steep” relative to optimal bids
  - Bidding too high during INC hours and too low during DEC hours
  - Sell less than ex post optimal (column 6,7)
- Many generators focus in bilateral market
- If so, overall performance is substantially higher
- Upper bound on total profitability (column 8) ranges from 41% to 98% (mean 80%)

Additional Tests of Profit Maximization

- Assumption: uncertainty “parallel shifts”
- They may be “pivot”
- If assumption violated ⇒ ex post optimal price-quantity points is a “cloud” of points that cannot be connected by an increasing supply function
- Then ex post if no informative for ex ante profitability and method fails
- Alternative assumptions tested and the same results.
- One important alternative: update by recent bids
  - use aggregate bids and own bids for day $t-3$ and calculate aggregate rival bids on day $t-3$
  - assume rivals use the $t-3$ bid schedule on upcoming day t
  - calculate ex post optimal bid function for various realizations of day t total balancing demand.

Additional Tests of Profit Maximization

- This is “naive best-response”
- Results close to ex post optimal profits
- $\Rightarrow$ findings of foregone profits do not arise from additive separability restriction
- Also test by Generalized Method of Moments (GMM) by Wolak (2003)
- Results: firms in this market violate first-order optimality conditions that need to hold for expected profit maximization

Explaining Deviations from Optimal Bidding

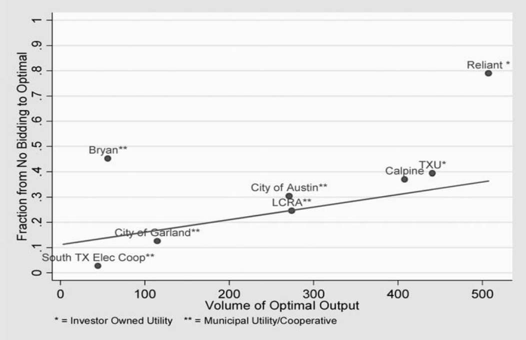
- Why deviations:
  - firm size
  - firm type (investor-owned utility versus municipal utility)
  - generation technology
- Most significant determinant: size or scale economies to participation in balancing market auctions
- Modest degree of learning by small firms

Participation costs & scale econ. in performance

- Fixed cost to “participate”
- “participate” mean quantity would not be zero
- They bid s.t. to not being called
- Fixed costs i.e. not worth to calculate mark-up
- Qualified scheduling entity (QSE) only can bid
- They bid for their own and others
- High fixed cost to become a QSE
- 40 points to submit bid
- QSE use more point for their own companies
- Reliant use on average 22.2 points
- Average is 13 points
- “coarse-grained” bidding strategies (Kastl (2006))

Performance vs. Stakes in Balancing Market

- For firms serving their own entity (QSE)



- Even conditional on paying the fixed cost of becoming a QSE, scale economies still appear to matter

Relationship Profitability and Firm Charac

	(1)	(2)	(3)	(4)	(5)
Size (MW)	.00052	.00047	.00035	−.00015	−.00035
	(.00031)*	(.00026)*	(.00028)	(.00025)	(.00024)
Size*OwnBidder				.00101	.00132
				(.00044)**	(.00042)***
OwnBidder				−.071	−.215
				(.111)	(.109)*
Merchant firm		−.098	−.167		−.170
		(.135)	(.146)		(.098)*
Municipal		.048	.025		.047
		(.135)	(.142)		(.089)
Coal			−.021		.043
			(.113)		(.120)
Combined-Cycle			.082		.127
			(.058)		(.071)*
Constant	.100	.158	.200	.158	.262
	(.054)*	(.142)	(.152)	(.058)**	(.098)**
Observations	34	34	34	34	34
R^2	.15	.28	.31	.34	.50

Relationship Profitability and Firm Charac

- Column 1: “scale hypothesis”
  - a 1000 MW increase in sales is associated with a 52% point increase in Percent Achieved
- Column 2: “corporate governance” no effect
- Technology mix not affect its performance
- Larger stakes are associated with higher performance for firms that serve as their own bidders
- Threshold for in-house bidding 71 MW

Learning

- Test time trends in bidder performance

	All Firms	Top 6 Firms	Non-Top 6 Firms
Days before opening of market	.00031	.00033	.00028
	(.00010)**	(.00029)	(.00009)**
Volume optimal output (GWh)	.16	.25	.09
	(.06)**	(.10)*	(.06)
Off-peak season	.01361	−.04437	.03164
	(.01892)	(.03799)	(.01885)
Constant	.02330	.21053	−.01441
	(.03030)	(.07503)**	(.02886)
Observations	9765	2103	7662
R^2	.25	.18	.11

- Dependent: Percent Achieved for firm i on day t.
- Controls seasonality, bider FE,
- Every 100 days 3% improvement
- Not significant for top six bidders

Quantifying Efficiency Losses

- Inefficiencies not least-cost production
- Bid above in INC not called despite low-cost
- Similarly in DEC side
- Counterfactual bidding behaviors
- Benchmark for efficiency: competitive bidding

Bidding Counterfactual	Average Production Cost
Actual bids for all firms	\$29,874
Strategic firms Bid MC, others bid actual	\$28,671
All firms bid MC (Vickrey auction)	\$23,571
Total efficiency losses	\$6,303
Strategic bidders	\$1,203
Nonstrategic bidders	\$5,100

Quantifying Efficiency Losses

- Average hourly dispatch costs in balancing market
  - Actual: $29,874
  - Marginal cost bidding $23,571
  - 27% higher
- Sources of inefficiency
  1. strategic exercise of market power (large firms face steeper residual demand functions and thus have incentives to bid steeper than marginal cost)
  2. behavior of small generators (exclude themselves by steep bid function)
- To measure: separate firms to
  - "strategic" bidders: exercise market power optimally
  - "nonstrategic" bidders: bid excessively steep schedules to minimize their participation

Quantifying Efficiency Losses

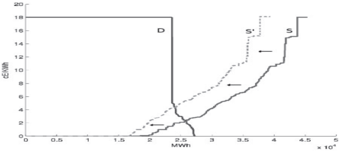
- Counterfactual: only strategic ignore their market power
- Non-strategic the same as actual
- Strategic: top firms: Reliant, TXU, Calpine, Brownsville, Bryan, Tenaska
- Total inefficiency: $6303 per hour, or 27% of total cost of efficient generation
- Efficiency loss due to market powe: $1203
- 81% of observed efficiency loss is due to steep bid schedules submitted by nonstrategic bidders

Introduction

- Reguant, Mar. "Complementary bidding mechanisms and startup costs in electricity markets." Restud (2014)
- Complementarity across goods or combination auctions: "packages"
- Intertemporal cost complementarities b/c of startup costs
- PJM, CA, Spanish: allow firms to express their startup costs
- Dynamic costs, dynamic strategic bidding, & market power
- Augmented auctions: offers increasing step bids (simple bids) +express a variable & a fixed cost component that needs to be recovered within the day
- If this minimum revenue not covered $\Rightarrow$ its hourly simple bids are taken out from the auction + no production

Introduction

- Units not recovered by their revenue requirement, are taken out iteratively, shifting supply curve inwards to S'



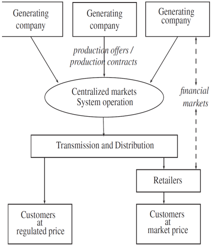
- Multi-unit auction,
- 1^st stage: Simple bids to estimate marginal costs (Wolak, 2007) + financial contracts (Hortaçsu, Puller, 2008; Allcott, 2013) jointly
- Identification strategy of both: marginal costs at power plant + forward contracts at firm level
- 2^nd stage: complex bids to identify startup costs

Introduction

- Startup costs
  - help reconcile strategic markups across hours (night hours)
  - limits price discrimination across hours

Market & Data

- Spanish: centralized markets (55%)+production bilateral contracts (33%)+financial contract (12%)



- Simple bidding:
  - Each hourly step function up to 25 steps per unit
  - Price: positive (or zero) + capped at 180 E/MWh
- Complex bids complement simple bids, unique for whole day

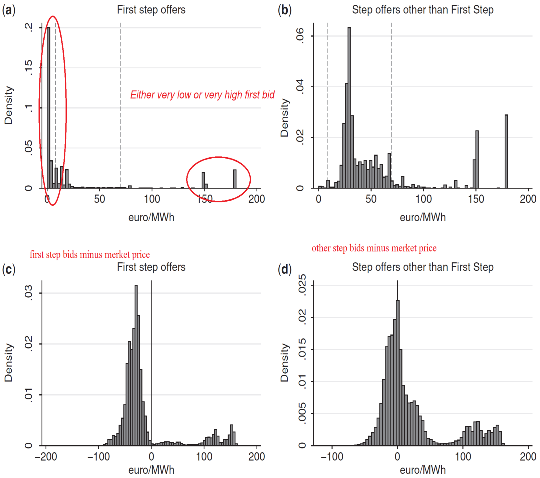
How do firms use simple bids?

- Mkt sharw: Endesa (27%), Iberdrola (21%)
- Coal (25%), nuclear(20%), natural gas(20%), renewables(20%) Hydraulic(10%)
- Study on thermal units (gas, nuclear), use complex bids

	Mean	Median	St.dev.	Min	Max	N.Obs.
Hourly market price (€/MWh)	34.1	32.1	9.1	7.0	69.7	2,880
Number of thermal units	78.56	78.00	2.46	73.0	83.0	120
Average simple bid						
First step price (€/MWh)	29.5	1.0	55.1	0.0	180.3	174,731
Other steps price (€/MWh)	67.9	54.3	47.7	0.0	180.3	823,467
First step quantity (MWh)	191	190	126	1	823	174,731
Other steps quantity (MWh)	43	22	66	1	803	823,467
Average complex bid						
Fix component (K€)	38.7	0.0	118.5	0.0	605.0	6,395
Var. component (€/MWh)	51.9	39.2	29.7	0.0	180.3	6,395

- Either very low (zero, to run) or very high first bid (to shut down)
- Extreme bids more frequent when no complex bid or production contract
- Strategic bid to (not) run, crucial role of start-up cost

Distribution of simple bids



How do firms use complex bids?

- Complex bids: run or not
- 66.1% use complex bids
- 23.2%: startup decisions by in advanced production contracts
- The rest using extreme simple bids to run or not
- Conditional on using complex bids: incentive compatible for a non-strategic firm to bid variable component of their complex bid equal to marginal cost of inputs, and fixed component equal to its startup cost
- For a strategic firm unclear

Model: Multi-Unit Auction with Complex Bid

- $i = \{1, \cdots, N\}$ firms, own units $j = \{1, \cdots, J_i\}$
- Simple bid pair of price and quantity: (b_{ijhk}, g_{ijhk}) hour h, step K (max $\bar{K} = 25$)
- Complex bid (daily) pair of fixed and variable cost: (A_{ij}, B_{ij})
- Pay equilibrium price p_h
- Discarded unit at equilibrium if:

$$\underbrace{\sum_{h=1}^{24} p_h q_{ijh}}_{Gross\ Revenue} < \underbrace{A_{ij} + B_{ij} \sum_{h=1}^{24} q_{ijh}}_{Minimum\ Revenue}$$

- Market clearing: recursively clear market with those satisfying complex bid (equilibrium set s^*)

Profit and Cost functions: structural parameters

- s accepted set. Expected profit:

$$E_{-i}[\Pi_i(b,g)] = \sum_{s\in S} P(s|b_i,g_i) E_{-i}[\Pi_i(b_{is},b_{-is})|s]$$

- where

$$\Pi_i(b_{is},b_{-is}) = \left(\sum_{h=1}^{24} p_h(b_{ihs},b_{-ihs})(Q_{ih}(b_{ihs},b_{-ihs}) - \nu_{ih})\right) - \sum_j C_{ij}(q_{ij}(b_{is},b_{-is})$$

- with cost function (with start-up costs)

$$C_{ij}(q_{ij}) = \sum_{h=1}^{24}\left(\alpha_{ij1}q_{ijh} + \frac{\alpha_{ij2}}{2}\tilde{q}_{ijh} + \frac{\alpha_{ij3}}{4}(q_{ijh} - q_{ij,h-1})^2\right)$$

Optimality Condition

- Complex bid: indifferent to run or not

$$E_{-i}\left[\Pi_i^{j,in}(b,g) - \Pi_i^{j,out}(b,g) | \sum_{h=1}^{24} p_h q_{ijh} = A_{ij} + B_{ij} \sum_{h=1}^{24} q_{ijh}\right]$$

- Simple bids

$$\sum_{s \in S} P(s|_i, g_i) \frac{\partial E_{-i}[\Pi_i(b)|s]}{\partial b_{ijkh}} + \sum_{s \in S} \frac{\partial P(s|_i, g_i)}{\partial b_{ijkh}} E_{-i}[\Pi_i(b)|s, \frac{\partial P(s|_i, g_i)}{\partial b_{ijkh}} \neq 0] = 0$$

- Paper also uses these two sets of equation as moments in structural estimation of parameters $\theta_i = [\alpha_i, \beta_i, \gamma_i]$