

# **Designing Market Rules for a Competitive Electricity Market**

by

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## **Optimal form of re-structured industry is solution to a Market Design Problem**

Set the number and size of market participants and the rules for determining revenues each firm receives so that the combined actions of each participant acting in its own best interest will produce a market outcomes as close as possible to regulator's desired outcome.

Tools regulator can use to solve market design problem

- 1) Set rules of market operation
- 2) Alter market structure

For a fixed market structure, there is a set of market rules that solves the market design problem.

For some market structures, many sets of rules yield market outcomes very close to the regulator's desired outcome.

For certain market structures, only a few sets of market rules yield outcomes close to regulator's desired outcome. (Because of history, more often in this situation.)

Most industries start with regulated monopolist that is very powerful politically, so that drastic structural remedies, such as plant-level divestiture or vertical divestiture, are not possible.

Therefore, implementing optimal market rules for actual market structure is most often crucial to the success of an industry re-structuring.

## **Purpose of Talk**

Discuss important aspects of the market rules choice in a market design problem.

Assess impact of these choices on the performance of the resulting electricity supply industry.

## **Important Features of Market Rules Choice**

1. Flexibility of bid functions submitted by firms
2. Protocol for translating bids into market prices—Price determination process.
3. Demand-side involvement in price-determination process
4. Impact of financial or physical hedge contracts on generator bidding behavior
5. Mandatory versus voluntary pools
6. Ex ante versus ex post prices and quantities
7. Methods for managing system reliability

## **Flexibility of bid functions submitted by firms**

In all day-ahead markets, generating firms submit bid functions that can vary on a load period (either hourly or half-hourly) basis.

The market rules constraint the form of the bid functions

Constraints on feasible bids functions can impact market outcomes

Two examples—England and Wales and State of Victoria in Australia

## **Market Rules in England and Wales**

Mandatory day-ahead spot market for electricity with market-clearing prices set on a half-hourly basis using *ex ante* perfectly inelastic demand for electricity.

Two strategic weapons to influence market-clearing electricity prices:

(1) the price at which unit is willing to supply electricity from a fixed portion of each generating facility for the entire next day

(2) the half-hourly decision of whether or not to make that portion of each generating facility available to be called upon by NGC to produce power.

Each generating set (genset) a firm owns can be divided into 3 bid increments.

Each day the firm can set 3 prices and 144 quantities for each genset it owns.

## **Market Rules in Victoria Power Exchange**

Similar to UK in that available capacity bid can be changed on a half-hourly basis but price bid for plant can only be changed on a daily basis.

Ten quantity bid increments per genset, so there are 10 daily prices and 480 quantities per genset.

Optimal amount of bid flexibility must balance two effects

- 1) Given the other generator's bid functions, one generator can more easily tailor its bids to steal market share from the other generators with lower priced bids
- 2) Given the other generator's bid functions, one generator can more easily construct complex within day punishment mechanisms to enforce higher market prices.

Which effect dominates is an empirical question.

## **Protocol for translating bids into market prices–Price determination process**

Two examples–England and Wales and State of Victoria in Australia

### **Market Rules in England and Wales**

System marginal price (SMP) is the price bid on the marginal genset required to satisfy NGC's forecast of each half-hour's total system demand for the next day.

Final price received by generators–Pool Purchase Price

$$PPP = SMP + CC,$$

where  $CC = LOLP \times (VOLL - SMP)$ , LOLP is the loss of load probability, and VOLL is the value of lost load.

VOLL represents the per KWH willingness of customers to pay to avoid supply interruptions. Set at £2,000 per megawatt-hour (MWH) for 1990/91 and has increased annually by the growth in the RPI since.

The LOLP is determined for each half-hour as the probability of a supply interruption due to generation capacity being insufficient to meet demand.

Price paid mostly by RECs purchasing electricity from the pool to sell to their final commercial, industrial and residential customers, Pool Selling Price, contains UPLIFT charge

$$\text{PSP} = \text{SMP} + \text{CC} + \text{UPLIFT} = \text{PPP} + \text{UPLIFT}.$$

The costs of supplying the difference the forecasted demand and the realized demand for the day is recovered through the UPLIFT charge.

## **Market Rules in Victoria Power Exchange**

Although still an ex ante market, VicPool closer ex post market than E&W market.

Half-hourly spot prices paid to all generators are determined by

- 1) Intersection of net (of demand-side bids) aggregate supply function with VPX's forecast of 5-minute ahead system demand
- 2) This yields a 5-minute ahead ex ante dispatch price
- 3) Half-hourly spot price is average of 6 six 5-minute ex ante prices for that half hour— $P_{\text{spot}} = (P_1 + P_2 + P_3 + P_4 + P_5 + P_6)/6$ .

Because market clears in very close to real-time, VicPool does not have an UPLIFT charge, as is the case in the E&W pool.

The E&W price determination process rewards capacity withholding with higher LOLP value and therefore a higher CC. The CC is, by far, the largest component of the very high PSPs that have occurred in the E&W market.

Capacity withholding implies steeper bid functions by major players, which in turn implies more inelastic residual demand functions faced by major players.

This implies less aggressive bidding by major players in E&W versus VPX.

### **Demand-side involvement in price-determination process**

Uncertain demand at time bids submitted are increases aggressiveness of bids

Price responsive demand increases aggressiveness of bids

Without price-responsive demand, market designer eliminates half of the mechanism that competition should lead to lower prices. (PX versus Real-Time Energy in CA).

Analogue: Airline ticket pricing with all business travelers.

## **Impact of financial or physical hedge contract on generator bidding behavior**

Financial two-sided hedge contract is a gamble on the market price for a fixed number of units of capacity.

$Q_{id}$ : Total market demand in load period  $i$  of day  $d$

$SO_{id}(p)$ : Amount of capacity bid by all other firms besides Firm A into the market in load period  $i$  of day  $d$  as a function of market price  $p$

$DR_{id}(p) = Q_{id} - SO_{id}(p)$ : Residual demand faced by Firm A in load period  $i$  of day  $d$ , specifying the demand faced by Firm A as a function of the market price  $p$

$QC_{id}$ : Contract quantity for load period  $i$  of day  $d$  for Firm A

$PC_{id}$ : Quantity-weighted average (over all hedge contract signed for that load period and day) contract price for load period  $i$  of day  $d$  for Firm A.

$\pi_{id}(p)$ : Variable profits to Firm A at price  $p$ , in load period  $i$  of day  $d$

MC: Marginal cost of producing a MWH by Firm A

$SA_{id}(p)$ : Bid function of Firm A for load period  $i$  of day  $d$  giving the amount it is willing to supply as a function of the price  $p$

Assume market clearing price  $p$  is determined by solving for the smallest price such that the equation  $SA_{id}(p) = DR_{id}(p)$  holds.

The magnitudes  $QC_{id}$  and  $PC_{id}$  are usually set far in advance of the actual day-ahead bidding process.

Generators sign hedge contracts with electricity suppliers or large consumers for a pattern of prices throughout the day, week, or month, for an entire or fiscal year.

Variable profits (profits excluding fixed costs) to Firm A for load period  $i$  during the day  $d$  at price  $p$  as:

$$\pi_{id}(p) = DR_{id}(p)(p - MC) - (p - PC_{id})QC_{id} \quad (2)$$

Once the market clearing price is determined for the period, equation (2) can be used to compute the profits for load period  $i$  in day  $d$ .

Note that unless its bidding strategy can effect the market-clearing price  $p$ , Firm A's profits are unaffected by its bidding strategy given  $PC_{id}$  and  $QC_{id}$ .

Re-write equation (2), the realized period-level profits of Firm A, as:

$$\pi(p) = (DR(p) - QC)(p - MC) + (PC - MC)QC. \quad (5)$$

Note that second part of expression is fixed from a day-ahead perspective.

Greater levels of contracting cause more aggressive bidding to occur.

For a large enough amount of contracting, bidding negative or zero prices is profit-maximizing.

Higher levels of contract cover by one firm makes higher levels of contract cover by one firm make more aggressive bidding by other firm optimal and higher amounts of contracting optimal.

Vesting contracts used to mitigate market power.

## **Mandatory versus voluntary pools**

Mandatory pool—all electricity produced in a given load period sells for the same price

Voluntary pool—many different prices for electricity produced in a given load period

If financial contracting is prohibited from mandatory market, the prices can become extremely volatile—California ancillary services markets.

In an uncongested transmission market, delivery of bilateral contracts occurs with probability one, whereas delivery of financial contract quantity is not assured unless bid price is less than market price.

## **Ex ante versus ex post prices and quantities**

In E&W a major component of PSP is known on a day ahead basis and demand that sets market price is known before bids submitted.

In VPX, neither price nor quantity demanded is known on a day-ahead basis.

## Methods for managing system reliability

Procure ancillary services such as regulation, spinning, non-spinning and replacement reserve on a long-term contractual basis

Procure ancillary services from a spot market.

Thinness of market problem—number of generators that can provide service

Congestion management problem—geographic area over which market is run

Reliability must-run contracts problem—very lucrative opportunity cost to bidding into market creates opportunity to gamble on bid price with a positive expected return.

During certain time periods RMR unit owner know with probability one that they will be dispatched and receive payment  $P$ . Therefore, they will bid so that the following equation is approximately true:

$$P = (\text{probability of being called by market}) \times (\text{market price if called})$$

This implies a bid price that is significantly higher than  $P$ .

## **Market design problem has many dimensions**

Economic analysis has much to contribute to optimal design of market rules

Impact of market rules can be subtle because markets are interconnected

- Real-time energy price cap and PX prices in CA

- RMR contracts and ancillary services prices in CA

In a competitive market, it is never optimal for a firm to bid the marginal cost of its generating units

Firms continually attempt to exploit upward slope of residual demand. The goal of market design problem is to leave all firms with as elastic as possible residual demand curves.