Real Time Pricing and Market Power: A New Zealand Case Study

By Stephen Poletti

INTRODUCTION

There are a number of features of electricity markets which make them quite different to most other markets. Electricity cannot be stored, or at least it is uneconomic to store significant amounts of electricity. Thus supply must equal demand instantaneously. Too much or too little supply may lead to rolling blackouts or even system collapse. Many customers cannot be billed for time of use consumption (meter reads monthly or more). As a result there is very little demand response. Wholesale prices typically vary over the course of a day by 100% or more, with price spikes of 10 or even 100 times the average price not uncommon.

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Many economists have argued that electricity markets would work better if customers were charged the real time price for electricity. The advantages of real time pricing cited include more elastic demand which may lead to a reduction in market power. It is also argued that customers will reduce consumption, when demand is high and electricity expensive to produce, and consume more during the off peak. This in turn should lead to higher effective capacity utilisation and a more efficient market.

As well as inelastic demand electricity markets have a hard constraint on supply once all generations are producing at full capacity. This means that supply is inelastic above total generation capacity. The combination of inelastic supply and demand can cause market porker issues for electricity markets. For example Borenstein (2002) concludes his analysis of California's power crisis failure:

> "….Electricity Markets have proven to be more difficult to restructure than many other markets that served as models for deregulation --- including airlines, trucking, natural gas and oil --- due to the unusual combination of extremely inelastic supply and extremely inelastic demand. Real-time pricing and long-term contracting can help to control the soaring wholesale prices recently seen in California (p210)."

Whilst there is general agreement that more customers on real time pricing contracts is desirable there has been surprising little theoretical work investigating the quantitative gains that might be expected. A key paper that does do this is Borenstein and Holland (2005). They model the electricity market as competitive and argue that "increasing the share of customers on RTP is likely to improve efficiency, although surprisingly it does not necessarily reduce capacity investment, and is likely to harm customers already on RTP…Efficiency gains from RTP are potentially quite significant".

Our intention here is to extend the work of Borenstein and Holland (2005) to a setting with market power. As will be seen we make quite different assumptions about the retail market and the shape of the demand functions in our quantitative analysis which leads to quite different results even in a setting with perfectly competitive markets.

MARKET MODEL

We consider here an Energy Only market with wholesale firms offering capacity into the spot market at a specified price with retail companies buying from the spot market and on-selling to their customers.

A fraction β of customers are on RTP contracts with their retail company and face a time varying price p_t, with the rest paying a fixed price p which doesn't vary with their time of consumption. We will assume there are T time periods with different demand realisations specified from lowest to highest demand. Demand in each period is $D_t (p,p_t) = \beta D_t (p_t) + (1-\beta) D_t (p)$. Power companies have access to different types of technologies and will build and run new capacity according to the merit order. Retail competition is modelled as perfectly competitive, however the retail companies can charge a fixed fee to customers. In equilibrium they charge a fixed fee to their customers paying the fixed price only. For customers on RTP contracts the retail firm just passes through the spot-market price.

The wholesale market is modelled using a Cournot approach. There are N firms which have access to different types of technologies – they will build and run new capacity according to the merit order. For linear demand functions Poletti and Wright (2016) solve for the prices and find that as the fraction of customers on RTP plans increases off-peak prices tend to increase and peak prices decrease.

NEW ZEALAND MARKET SIMULATION

We will consider a simple stylised version of the NZ electricity market with three types of plants baseload, mid merit and peakers. Capital and running costs for both hydro and geothermal are similar and hydro does play a significant role as baseload generation, however, here we choose geothermal plants as the baseload technology as capacity factors are over 90%. Although much of New Zealand's generation is hydro it plays a complex role in the market. A significant amount of hydro always bids into the spot market at a price of zero due to run of river generation or minimum flow rates below the hydro dams, however it also plays a role as mid merit and peaker plants due to its flexible ramp rates and limited storage capacity of the storage lakes. Table 1 shows the data for overnight costs, capacity factors, variable costs and calculated fixed costs assuming a 35 year payback and a real interest rate of 5%. The break-even prices p_t^* are also listed in the table. These are the prices which would allow all the generators to just cover their fixed and variable costs.

In our stylised model we make the assumption that there are only three periods with the marginal technology as demand increases from period one being geothermal, CCGT and peakers. Under these assumptions f_1=0.32, f_2=0.48 and f_3=0.2. Demand is ranked for each period between 2004-2014, from highest to lowest and we specify that the demand in period one is the average demand for the lowest 32 per cent of demand periods and so on for the other periods.

Technologyy	OC($/kw)	FC($/MWh)	VC($/MWh)	cf	pt*
Geothermal	5200	35	10	0.9	-1
CCGT	1800	12	50	0.68	50
Peaker	1250	12	70	0.2	114

Table 1: Generator information

To make further progress for our quantitative analysis we need to estimate the linear demand parameters. We will use empirical elasticity estimates and the known demand for the recent study of the South Australian electricity market Fan and Hyndman (2011) estimates the demand elasticity ε (that is the elasticity of demand with respect to the average price) to be approximately -0.3. Our reading of the literature is that most empirical estimates lie between --0.2>ε >-0.4 so a choice of ε=-0.3 seems reasonable.

The other parameter that we need to estimate is β. There is little information on this except that nearly all commercial and household customers pay a fixed price. Accurate information for the New Zealand market is not available -indeed the Wolak report which investigated the extent of market power had the relevant data reduced in the publicly available version of the report. Our reading of the literature is that β =0.2 is a reasonable value to assume which is what we use in the analysis.

Average net demand for period 1 is 2807 MW, for period 2 it is 3887 MW and for period 3 it is 4659MW with average demand of 3696MW. Using the estimates for the elasticity and the fraction of customers paying the spot price gives the following demand functions.

$$D_3=6000-16$$
$$D_2=5000-16p$$
$$D_1=3800-16p$$

Figure 1 shows the estimated prices and how they change as β increases. The peak price computed for our estimated value of β is about $50 higher than the observed price of $154, the mid-period price estimate is about $35 too high, with the off-peak price estimate about $25 too low. The Cournot model here in, common with many Cournot mode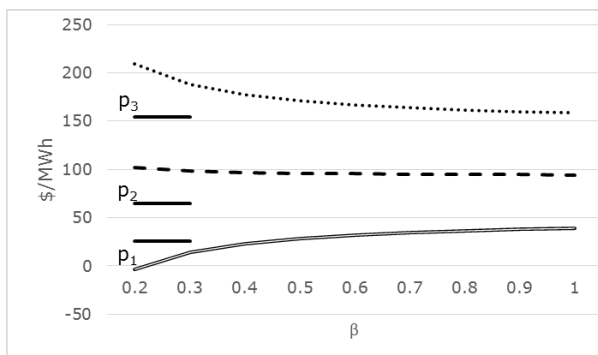ls of electricity markets tends to predict more market power than actually observed. This due a couple of factors. The first is that firms in general bid in supply functions in the market due to demand uncertainty which increases the effective residual supply elasticity faced by each firm and hence its ability to exercise market power. The other factor is that, in the New Zealand context, the big firms are all vertically integrated which reduces their incentive to exercise market power even though biggest firms are net sellers on the spot market}

One interesting feature is the way that the mark-ups differ as **β** increases. The peak price decreases and the off-peak price increases, with p_2 decreasing slowly. The fixed price stays the same and is approximately $90/MWh. As β increases the capacity mix changes with less need for mid merit and peak capacity and much more baseload which is one of the key reasons why real

Figure 1. Estimated prices as a function of β. The solid lines are the observed prices.

time pricing is advocated. Overall less capacity is needed which contributes to the efficiency gains as customers switch to RTP.

Table 2 shows how revenue, profits, consumer surplus (CS), social welfare (SW), total costs (TC) and social welfare for a competitive market (SW*) change as β increases The increase in social welfare, as β increases from 0.2 to 1, in a setting with market power is about 20% higher than the increase in social welfare for a competitive market. However, the increase in social welfare looks to be less than that reported by Borenstein and Holland (2005). They do not report increases in social welfare directly, instead reporting on change in total surplus (social welfare) as a fraction of revenue. By this

β	% Change Revenue	% Change Profits	% Change in CS	% Change in SW	% Change in TC	% Change SW*	% Change in TC
0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.4	-4.9	-8.7	5.1	0.8	-2.4	0.5	-2.4
0.6	-7.2	-11.6	7.2	1.4	-4.7	1.0	-4.7
0.8	-8.9	-12.9	8.5	1.9	-7.1	1.5	-7.1
1.0	-10.3	-13.4	9.5	2.4	-9.5	2.0	-9.5

Table 2: Simulated market outcomes of customers switching to RTP

measure our calculations (not reported in the table) show, for the competitive market, an increase in the change in total surplus (social welfare) as a fraction of revenue of 4.1 per cent going from β=0 to β=1which compares to the figure of 8.8 per cent reported by Borenstein and Holland (2005) for constant elasticity demand functions with ε=-0.3.

There are a two possible reasons for the different results. The first is that Borenstein and Holland use linear pricing whereas we assume that traditional customers are on a two-part tariff. The second is that the demand functions assumed here are linear. The constant elasticity demand functions used by Borenstein and Holland do not seem realistic for high prices as the consumer surplus is infinite, which is why they report only changes in consumer surplus. It may well be that the unrealistic shape of the demand function for extremely high prices may lead to an over estimate of the consumer surplus and in turn an over estimate of the change in consumer surplus as β increases.

Turning to table 2 it can be seen that the percentage change in profits and consumer surplus are significantly higher than the overall change in social welfare as β increases. Profits decrease by -13.4 per cent with consumer surplus increasing by 9.5 per cent. Whilst the overall increase in social welfare is relatively modest the gain to customers is considerable. Hence one of the key findings of our investigation is that encouraging or mandating a movement from traditional flat rates to real time pricing may have a significant role to play as a policy to increase competition. The large drop in profits seen also suggests that firms may not encourage such a shift. The other noteworthy finding which can be seen in the table is the large decrease of almost 10 per cent in system costs (which includes equilibrium investment and running costs). As β increases the demand profile over the day is flatter which leads to higher average capacity factors and lower system costs. Overall market revenue also falls significantly. The other pattern that emerges from the table is that the increases in consumer surplus, system efficiency and social welfare are relatively higher for initial increases in β which agrees with the results presented in Borenstein and Holland (2005).

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