From: energymarkets@mbie.govt.nz
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Region
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Category
Individuals, Researchers and Academics

Do you accept these terms & conditions?
Yes

A1. Establish a consumer advisory council
A2. Ensure regulators listen to consumers
B1. Establish a cross-sector energy hardship group
B2. Define energy hardship
B3. Establish a network of community-level support services to help consumers in energy hardship
B4. Set up a fund to help households in energy hardship become more energy efficient
B5. Offer extra financial support for households in energy hardship
B6. Set mandatory minimum standards to protect vulnerable and medically dependent consumers
B7. Prohibit prompt payment discounts but allow reasonable late payment fees
B8. Seek bulk deals for social housing and/or Work and Income clients
C1. Make it easier for consumers to shop around

It is important for consumers to be able to shop around for a retailer most efficiently meeting their needs. More importantly however, it is necessary to have viable retail competition so that there are a sufficient number of serious retailers a consumer can consider. We note 90% of the retail market consists of the five largest gentailers. This might imply that asset-light retailers are not commercially viable entities (See Boroumand and Zachmann for a comprehensive study on the risks associated with this organizational structure). We suggest a study of alternative models that may including coupling of retailing with other electricity market agents (e.g. large consumers of electricity), having regulated utilities that are distributor-retailers (similar to many US markets), or even the complete abolition of retailers with their functions taken over by industry players (see Basic Electricity Service).

Boroumand, R. H., and Zachmann G., (2012) Retailers' risk management and vertical arrangements in electricity markets, Energy Policy, 40, 465-472.
Joskow, P. (2000) Why do we need electricity retailers? Or can you get it cheaper

wholesale? Revised discussion draft, MIT, Massachusetts.

C2. Include information on power bills to help consumers switch retailer or resolve billing disputes
C3. Make it easier to access electricity usage data
C4. Make distributors offer retailers standard terms for network access
C5. Prohibit win-backs
C6. Help non-switching consumers find better deals
C7. Introduce retail price caps
D1. Toughen rules on disclosing wholesale market information
D2. Introduce mandatory market-making obligations

It may be very helpful for market makers to be obligated to enter into contracts with asset-light retailers. This option should be considered.

D3. Make generator-retailers release information about the profitability of their retailing activities
D4. Monitor contract prices and generation costs more closely

The pricing-review options paper found no evidence to support excessive profits by generators. Stephen Poletti provided some analysis [1] indicating that markups of generator offers above short-run marginal cost yielded market power rents of about (NZ)$6 billion between 2010 and 2016. For varying reasons, Poletti's analysis has been dismissed by the review, and a number of submitters.

In discussing these and other results, one needs to be careful in the use of terminology. Market rents (or operating surplus) measure the money accrued from selling electricity at a price above its marginal cost. These rents must be distinguished from "profits".

First, the rents are measured in terms of wholesale market sales at wholesale spot prices. If a generator has sold a hedge contract then this will price some of these sales at the contract price rather than the spot price. For example, historical wholesale price data show that some generators were paid below their fuel cost for generation in some periods in early 2013. If they had sold a hedge at $80/MWh, say, for this generation then they would have been compensated for the apparent loss. Since contracts typically trade at a premium over expected spot prices [2] , long-term average rents tend to underestimate the operating surpluses that would accrue if accounting for contracts as well.

A second mistake is to confuse rents with "profits" which account also for fixed costs (labour, buildings, insurance, loan interest etc.). Estimating profits using market rents is possible from published accounts, but requires detailed breakdowns of costs and revenues.

A third mistake is to confuse the short run and the long run. In the short run, optimal economic dispatch occurs when generators are dispatched in the merit order of short-run marginal cost (SRMC). So generators should offer their generation at this level. It is easy to see from a diagram that optimal dispatch provides rents to infra-marginal generators, but no rent for the marginal generator. How do they recover their fixed cost?

In markets with demand response the price when all generators are at capacity is set by a demand curve defining the marginal utility of electricity consumers. When demand is inelastic then a price cap (value of lost load =VOLL) is defined at which involuntary load shedding occurs. In this case when all generators are at capacity then prices rise towards VOLL, and all generators earn rents (even if they are peakers). In a risk-neutral setting the theory then establishes that in the long run equilibrium all generators invest or divest to earn exactly their long-run marginal cost (LRMC). The myth is that generators need to offer generation at LRMC to earn enough profits to induce them to invest. Not only can this cause inefficient dispatch by altering the merit order, but more importantly it biases investments away from socially optimal ones.

Poletti's analysis was an update of that performed by Frank Wolak in 2009 [3] . Both analyses seek perfectly competitive counterfactual outcomes. This is very difficult to do if one properly accounts for stored hydroelectricity with uncertain inflows. A comprehensive model that does this is described in two recent papers, the first by Philpott and Guan [4], that describes the methodology in detail and applies it to the historical years 2012 and 2013, and a forthcoming paper by Philpott and Guan [5] that gives results for 2008-2017.

Both papers use the DOASA optimization model and vSPD to compute a perfectly competitive counterfactual electricity price series for the ten years 2008 to 2017. They find that perfectly competitive prices are below market prices when MBIE estimates of gas costs are used (about $6/GJ), but track more closely when the cost of gas is increased to its reported opportunity cost as provided by First NZ Capital Securities Ltd (about $9/GJ). The counterfactual models show some notable deviations in historical wholesale prices:

(1) With low gas costs, South Island historical wholesale prices are higher than perfectly competitive counterfactual prices;

(2) February/March historical prices are often higher than perfectly competitive counterfactual prices;

(3) In some years, historical prices are below the short-run marginal cost of dispatched thermal plant.

The models have been run at different levels of risk aversion. Results vary from historical outcomes [6] , depending on assumptions of gas cost and the level of risk aversion of participants. The Electricity Price Review should note the following results from the computations:

MBIE gas costs results

(1) Using low gas costs the perfectly competitive counterfactual model uses between $200M and $600M less in gas and coal (depending on the degree of risk aversion) than historical generation over the ten-year period 2008-2017.

(2) Using low gas costs the perfectly competitive counterfactual model earns between $3.3B and $3.4B less Ricardian rent than the historical solution over the ten-year period 2008-2017.

(3) Historical Otahuhu prices when averaged over 2008-2017 are close to competitive average counterfactual prices.

(4) Historical Benmore prices exceed perfectly competitive prices by an average of $20/MWh for risk neutral operation, and an average of $15/MWh for risk averse operation over the ten-year period 2008-2017. This increase in South Island prices decreases HVDC transmission rentals resulting in a wealth transfer from the owner of the transmission grid to South Island generators.

(5) There is some evidence that wholesale electricity is marked up with respect to perfectly competitive benchmarks in early months of each year. Price premia decline later in the autumn, as more information accrues and contract levels are settled.

First NZ Capital Securities Ltd gas cost results

(6) Using high gas costs the perfectly competitive counterfactual model uses between $700M and $1200M less in gas and coal (depending on the degree of risk aversion) than historical generation over the ten-year period 2008-2017.

(7) Using high gas costs the perfectly competitive counterfactual model earns between $6B and $8B more Ricardian rent than the historical solution over the ten-year period 2008-2017.

(8) Historical Otahuhu prices when averaged over 2008-2017 are lower than average perfectly competitive prices.

(9) There is some evidence that wholesale electricity is overpriced with respect to

perfectly competitive benchmarks in early months of each year. Price premia decline later in the autumn, as more information accrues and contract levels are settled.

Summary

1. Outcomes of counterfactual analysis depend on assumptions of gas costs and levels of risk aversion. In market monitoring, it is therefore very important that gas costs and availability (and other) model inputs are disclosed and agreed upon by participants and the regulator.
2. When risk aversion is included in the doasa optimization model, and this is re-solved every month, it produces storage trajectories in simulation that avoid shortages over ten years. With low gas costs these outcomes can be achieved with price increases to signal the risk of shortage that are often more modest than those observed historically. Care must be taken in interpreting this assertion as the counterfactual storage trajectories tend to decrease this risk.
3. Differences in Ricardian rent over 10 years can vary widely depending on the assumptions underlying the counterfactual model. This makes it unwise to use these statistics on their own as a performance indicator. Notwithstanding this remark, the counterfactual models allow us to identify some market features that deserve further attention. These are
a. Price markups observed in February and March of each year;
b. Price markups observed in the South Island compared with counterfactual prices.

Footnotes:

[1] Poletti, S. (2018) Market power in the NZ wholesale market 2010-2016. Technical report, University of Auckland.

[2] F. Bevin-McCrimmon, I. Diaz-Rainey, M. McCarten, and G. Sise. Liquidity and risk premia in electricity futures. Energy Economics, 75:503-517, 2018.

[3] F.A. Wolak, An assessment of the performance of the New Zealand wholesale electricity market, May 19, 2009.

[4] Philpott A.B. and Guan Z. (2018) Benchmarking wholesale hydroelectricity markets with risk averse agents, www.epoc.org.nz.

[5] Philpott A.B. and Guan Z. (2019) Efficiency of the New Zealand wholesale electricity market 2008-2017, www.epoc.org.nz.

[6]A summary of results from this model is available in the PDF Powerpoint slide show EMBERSlides.pdf, downloadable from www.epoc.org.nz

D5. Prohibit vertically integrated companies

We do not favour this option. The analysis of vertical integration of generators and retailers is complicated. It is often cited as a reason for a thin contract market. This acts as a barrier to new entry in the retail market, and makes it difficult for large industrial loads to hedge their exposure. Both of these are negative effects. We note that the market-maker arrangements for the four largest gentailers has improved the liquidity of the contract market and believe it should continue and be improved where needed in order to maintain appropriate bid-ask spreads.

As noted in C1, we suggest a study of alternative models that may include market-maker obligations to offer contracts, or coupling of retailing with other electricity market agents (e.g. large consumers of electricity), having regulated utilities that are distributor-retailers (similar to many US markets), or even the complete abolition of retailers with their functions taken over by industry players. Any of these alternatives may lead to a much more efficient outcome than the current arrangements. However below we recap the role of contracts and vertical integration in imperfectly competitive markets.

Given an oligopolistic spot market, gentailers' participation in the contracts market is important, since it is well known (from Allaz and Vila [1]) that a generator selling in a forward market behaves more competitively in the spot market. (In fact it is also shown that it is in their interests to sell in the forward market.) Moreover, in imperfectly competitive markets, both contracts and vertical integration affect offer strategies, making them more competitive. The recent PhD thesis by Keith Ruddell [2] shows that the effect is the same in these two models if the integrated retail load is statistically independent of total load. When these loads are correlated (which happens in reality) vertical integration provides more competitive pressures on prices than contracts for differences. The rationale for this result is that firms are less incentivised to mark up the final tranches in their offer stack, since in high load scenarios in which that tranche is dispatched, a resulting high price would coincide with a high integrated retail load.

On the other hand, vertical integration is a hedge against risk in price and volume that can be more effective than hedge contracts (that account for price variation only). This reduction in risk can lead to more efficient investment decisions in perfectly competitive investment models with risk-averse agents. Details and models are discussed in the recent PhD thesis by Corey Kok [3].

Footnotes

[1] Allaz B. and Vila J-L. (1993) Cournot Competition, Forward Markets and Efficiency. Journal of Economic Theory. Volume 59, Issue 1.

[2] Keith Ruddell, Supply function equilibrium in electricity markets, PhD thesis, University of Auckland, 2017.

[3] Corey Kok, Electricity generation expansion under uncertainty and risk, PhD thesis, University of Auckland, 2017.

E1. Issue a government policy statement on transmission pricing
E2. Issue a government policy statement on distribution pricing
E3. Regulate distribution cost allocation principles
E4. Limit price shocks from distribution price increases
E5. Phase out low fixed charge tariff regulations
E6. Ensure access to smart meter data on reasonable terms
E7. Strengthen the Commerce Commission's powers to regulate distributors' performance
E8. Require smaller distributors to amalgamate
E9. Lower Transpower and distributors' asset values and rates of return
F1. Give the Electricity Authority clearer, more flexible powers to regulate network access for distributed energy services
F2. Transfer the Electricity Authority's transmission and distribution-related regulatory functions to the Commerce Commission
F3. Give regulators environmental and fairness goals

F4. Allow Electricity Authority decisions to be appealed on their merits
F5. Update the Electricity Authority's compliance framework and strengthen its information-gathering powers
F6. Establish an electricity and gas regulator
G1. Set up a fund to encourage more innovation
G2. Examine security and resilience of electricity supply
G3. Encourage more co-ordination among agencies
G4. Improve the energy efficiency of new and existing buildings