Electricity Authority
Market Development Advisory Group

By email: MDAG@ea.govt.nz

4 May 2020

Discussion Paper – High Standard of Trading Conduct Provisions: A Review by the Market Development Advisory Group

Mercury appreciates the opportunity to comment on the Market Development Advisory Group's (MDAG) review of the High Standard of Trading Conduct (HSOTC) provisions within the Electricity Industry Participation Code (the Code). We also commend MDAG on allowing for cross-submissions and we intend to use that opportunity.

Summary

Mercury does not support the implementation of the MDAG's proposal to implement a cost-based economic test as a trading conduct standard. Mercury does also not agree with the MDAG that its proposal would come at negligible cost. Mercury has identified impacts to competition and dynamic efficiency that are inconsistent with the Authority's strategic objective that the MDAG's analysis does not consider.

If implemented, the Authority would potentially be placed in the untenable position of having to assess for each trading period whether prices reflected economic costs with a sufficient margin to ensure new capacity is built and security of supply is maintained. It would likely become subject to intense lobbying to alter wholesale market outcomes based on differing views on what constitutes 'efficient' costs. We note that the Authority rejected implementing code changes in 2013 in response to calls for a single buyer to deal with perceived market power due to the challenges of undertaking the a similar type of economic cost-based analysis proposed by the MDAG.

Clarity is required for generators to resolve the uncertainty that has been created regarding the ability to use physical assets to manage risks in response to low probability, but high impact, outage events. Removing this ability through trading conduct provisions would reduce competition, increase costs to consumers and distort price signals for future generation investment. Mercury considers the MDAG's focus should be on pivotal situations where generators exercise market power to extract excessive economic rents rather than the prudent management of constraint risks. As a minimum, a series of worked examples should be urgently developed which lay out how the proposed Code would be interpreted by the Rulings Panel (and Courts) so that those participants who will be most affected by a potential proposed Code change can gain a better understanding of the intent of the Code and provide further feedback under cross submissions.

We further expand on the above points in the attachment to this cover letter. Please direct any questions on this submission to John Bright, Regulatory Strategist at john.bright@mercury.co.nz.

Yours sincerely,

Nick Wilson
Manager Regulatory and Government Affairs

John Bright
Regulatory Strategist

Attachment 1. Mercury commentary on MDAG discussion paper

Background and Problem Definition

New Zealand's electricity market is internationally recognised as world leading[1]. Price signals through the electricity wholesale and futures markets have led to highly efficient generation investment and retirement decisions over the past two decades. Currently the market is delivering around $900 million of investment in new generation development with a further $2 billion likely in the near term[2]. The wholesale market also delivered the efficient retirement of 450MW of gas fired thermal generation in 2015 following the development of lower emissions geothermal energy capacity. Each wave of investment and retirement was in response to clear signals from the wholesale market which investors understand and rely on for decision making.

No evidence is provided in the MDAG discussion paper that the six identified instances of local pivotal situations have led to significant long-term consumer detriment. Those instances that are identified are assessed as having relatively limited efficiency impacts[3]. The analysis of the risks from gross pivotal situations appears to be concerned with the theoretical potential incentive to raise prices, rather than actual observable consumer impacts.

Given the performance of New Zealand's electricity market to date, Mercury considers there is no evidence to suggest that any limited market power that might be available to participants has raised wholesale prices and brought forward generation investment sooner than would be otherwise be efficient or expected. Likewise, there does not appear to be evidence of generators being able to use market power to hold-up wholesale prices to defer the retirement of generation that was no longer economic. Mercury for example in 2015 mothballed its Southdown gas fired power station in the middle of its economic life due to market price signals that did not support its continuing operation. Similarly Contact Energy did the same with its Otahuhu CCGT plant in the same year.

Material efficiency impacts are not considered in the MDAG analysis

Mercury's main concern with the MDAG discussion paper is that it only considers a single option, moving toward an economic cost-based test for market power, and then assesses the implementation of that option as costless relative to the status quo.

Mercury considers the MDAG proposal will result in costs not considered in the analysis that would materially reduce competition and impact on the future dynamic efficiency of the market, acting against the Authority's statutory objective. This is due to the economic cost-based test applying to all trading periods, not just net pivotal situations and not distinguishing between situations where generators may be manipulating market power to extract excessive economic rents versus those where physical assets are legitimately used to manage price separation risks and reduce long run costs to consumers. This latter scenario has been a key area the industry has sought clarity on since the EA issued a warning to Meridian in 2017 that such behaviour was inconsistent with a high standard of trading conduct and that Meridian should have managed such risks through hedging arrangements or on its balance sheet.

Challenges of economic cost-based regulation

If implemented, the MDAG proposal would mean the Authority, via the Rulings Panel, would be required to arbitrate as to whether offer behaviour was consistent against its own assessment of reasonable economic costs. The Authority has previously provided a highly cogent and well-reasoned economic critique of the challenges of undertaking such assessments in 2013 in response to calls for the Authority to introduce code changes to introduce "a single entity to directly set electricity wholesale prices and generation investment". The Authority was categoric that "it will not be progressing Code changes… as it does not believe they are consistent with its statutory objective [and] will promote the long-term benefit of consumers"[4].

The Authority noted the significant deficiencies of economic analysis that had been undertaken in an attempt to claim that generators were manipulating market offers to extract super-profits at the expense of consumers. These included[5]:

- underestimation of the opportunity cost of hydro storage, that is the value of water preserved for later use;
- underestimation of the availability and opportunity cost of gas, particularly in the light of the decline of the Maui gas field;
- The 'competitive benchmark' price based on short run marginal costs used by the report to calculate market power rents was not sufficient to cover the costs of building new capacity and ensuring security of supply. The additional costs of, for example, payments to generators to provide capacity were missed from the calculations;
- The analysis was done in hindsight, and assumed perfect foresight on the part of decision-makers, with no allowance for the uncertainties parties face in the real world regarding future demand, plant availability and hydro inflows;
- The analysis used actual demand to estimate the competitive benchmark price in dry years, which ignored demand response to high wholesale prices and biased the competitive benchmark price in the study downwards; and

[1] International Energy Agency, Energy Policies of IEA Countries: NZ 2017 Review
[2] Mercury submission to MBIE's discussion document "Accelerating renewable energy and energy efficiency"
[3] Section 36 of MDAG discussion paper
[4] Electricity Authority (4 June 2013) "The Economics of Electricity" – pgs 2-3. See Attachment Two to this submission.
[5] *Ibid.* pg 8

- detailed analysis had not been done to establish that any excessive prices in the wholesale market had been passed on to consumers. Any effects may have been merely wealth transfers among generators.

The EA critique above highlights exactly the same challenges that would face the Authority under the MDAG proposal who would be required to construct their own models and assumptions to assess whether the offering behaviour from generators was reasonable across all trading periods. This would place the Authority in a highly challenging situation particularly given the difficulties of determining what the opportunity cost of hydro storage should be and would also require the regulator to have a detailed understanding of commercially sensitive information such as an integrated entity's sales positions in the retail market and hedging positions. Even with such inform, there would be substantial room for mis-interpretation, error and bias. The Authority itself has previously cautioned against such approaches in the context of the single buyer proposals:

> "Finally, but probably most importantly, any costs resulting from any planning errors will be borne by consumers and not producers and are likely to be much greater because of the difficulties of monitoring the performance of bureaucrats. The likelihood is that the surplus/shortage cycles experienced by New Zealand when NZED was the sole producer of wholesale electricity will be repeated with a deleterious effect on social welfare and the performance of the economy."[6]

While Mercury appreciates the MDAG are not proposing centralised planning of the electricity system, a shift toward economic cost-based market power test would have similar effects of undermining the efficient price discovery process which was the foundation of the shift toward the competitive market from government control.

The net effect of the MDAG proposal would therefore be to introduce de facto price regulation on the wholesale market and could have a chilling effect on capital flows into generation investment over the long term. The EA would also come under intense pressure to revise market prices from parties who stood to benefit from any revisions. Mercury observes this type of vexatious behaviour is becoming an increasing feature of the existing market and would only become exacerbated under the MDAG proposal.

MDAG proposal would reduce competition and reduce dynamic efficiency

Despite the potential for highly distorted generation offer behaviour and increased regulatory intervention in the wholesale market in response to an economic cost-based trading conduct test, the MDAG analysis claims there would be no costs associated with implementing its proposal.

Mercury does not consider this is plausible. If generators are prohibited for example from using physical assets to close transmission constraints to manage downside risks, one solution could be to no longer offer products in those regions thereby reducing retail competition. This would clearly run contrary to the achievement of the EA's statutory objective to promote competition.

Despite the claims from the Authority and the MDAG paper that generators should hedge such risks with financial risk management products, there is limited ability to do so and certainly not at the volumes required (hundreds of megawatts) in response to real-time outages of transmission and/or generation that happen very infrequently, as was the case for Meridian in 2017. The Financial Transmission Rights (FTR) market continues to develop but at present does not cover all regions. It also does not include any nodes on the 110kV network, auctions only occur monthly and in these auctions participants can only bid on FTRs for six individual months in the future. Therefore, FTRs are not a sufficiently liquid or appropriate to hedge in real time such large-scale risks. With no FTRs available on the 110KV network generators have no ability other than using their physical assets to manage price separation risks in these parts of the network.

Even if it were possible (which it currently isn't) to hold enough hedges in advance to cover such low probability, high impact risks, the outcome would be to significantly drive up hedge prices compared to the much lower cost option of generators managing such infrequent risks via physical assets. The long-term outcome would be higher-than-necessary costs to consumers with distorted price signals in the hedge market over-signalling the need for generation and transmission investment. This would therefore reduce dynamic efficiency and again act against the EA's statutory objective.

Mercury considers that, when faced with the uncertainty and risk of having to justify every trading offer, the most likely outcome will be that wholesale market traders will tend toward "set-and-forget" offer strategies which may under or over price electricity during peak and off-peak periods. This would reduce dynamic price signals to both supply and demand side participants over time.

Mercury is also unclear whether or how the MDAG proposal would allow for the hydraulic management of integrated river chains such as the Waitaki, Clutha and Waikato Hydro schemes where frequent shifts in offers are often required to adjust generation levels to avoid spill and to ensure adherence to minimum flow resource consent requirements. In the future with increasing

[6] *Ibid. pg 18*

renewables penetration and retirement of thermal generation, increased flexibility will be required from existing hydro generation to support the power system, yet it is unclear how the MDAG proposal might influence such outcomes.

The MDAG cost benefit analysis does not consider such impacts and in Mercury's view is not adequate to justify the implementation by the EA of the MDAG proposal.

Efficient pricing relies on promoting competition not economic costs

Mercury disagrees with the MDAG interpretation that efficient prices should always equate to underlying economic costs. Efficient prices are set through the price discovery process in competitive markets. Marginal prices in the wholesale market will be set with reference to what a participant considers is achievable before a competitor is able to compete away any surplus. In a competitive market, generators may offer energy at whatever level they wish but if this is above a competitive benchmark they will neither be dispatched nor earn revenue. The determination of price may therefore be unrelated to economic cost but rather reflect participant views regarding what the market will bear before competition reduces any return.

The MDAG proposal aims to mimic the effects of competition during periods of market power and limit pricing to the level assumed to have been in place had competition existed. As outlined above, this can result in significant distortions to the price discovery process and result in inefficiencies that are currently not quantified in the paper.

Given the potential for inefficiencies from distorted price discovery, the Authority has rightly been focussed on ensuring that barriers to entry into the market remain low such that any attempt to exploit market power to raise prices get competed away and that sufficient hedging products are available to reduce a participant's exposure to wholesale market temporary price fluctuations. In terms of the former, we are currently observing significant generation investment occurring suggesting there are few barriers to generation investment in New Zealand. In terms of the latter, the EA continues to work on a review and potential enhancements to the FTR regime and on long term sustainable arrangements for the market making in the futures market. This suggests there are other market and policy solutions that will reduce the potential for market power over time.

Need for problem definition, options and examples

Mercury is concerned that in drafting Code amendments the MDAG are leading towards a pre-determined outcome that favours the implementation of an economic cost-based test without a full assessment of the potential costs of distorting efficient price discovery and removing risk management options for current market participants.

The scope of the MDAG analysis has expanded from how to address limited pivotal situations to a view that generators should now have to justify positions taken in all trading periods with reference to economic costs. In our view, the focus should instead return to measures to address the original problem definition of net pivotal situations where participants have scope to manipulate market power situations to extract excessive economic rents. The current market trading conduct provisions were introduced in response to such an event but may be able to be clarified rather than replaced, with appropriate guidance and focus from the Authority.

Participants have not been able to meaningfully comment on other options other than the MDAG's preferred approach which, as discussed above, does not include a complete assessment of the competitive and dynamic efficiency costs from prohibiting the use of physical assets to mitigate risk. Mercury does not support the MDAG proposal proceeding to code change. As a minimum, a series of worked examples should be urgently developed which lay out how the proposed Code would be interpreted by the Rulings Panel (and Courts) so that those participants who will be most affected by the proposed Code change can gain a better understanding of the intent of the Code and provide further feedback under cross submissions.

Attachment 2. Economics of Electricity

The Economics of Electricity

4 June 2013

The Economics of Electricity

Dr Brent Layton
Chair

1. The Electricity Authority is an independent Crown entity with the power to amend the Electricity Industry Participation Code. It is also the only party able to do so. However, it can amend the Code only if it considers the proposed changes are consistent with the Authority's statutory objective "to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers." The Authority also has to subject any proposals to its Code Amendment Principles that involve extensive consultation and analysis before it makes any change.

2. The Code under which the New Zealand electricity market operates and the outcomes it has achieved have been subjected to a number of criticisms this year. On the one hand, major generator-retailers argued strenuously at the 2013 Downstream Conference for the Authority to slow-down its work programme to give more time for them to adjust to the pace of change. On the other hand, critics such as Mrs Molly Melhuish, Mr Bryan Leyland and Dr Geoff Bertram have claimed the Authority's regime is a light-touch approach to regulating the electricity markets and that the Authority needs to change the Code to alter the way prices are determined in the wholesale market.

3. The Authority has considered the calls from generator-retailers, and while it will look to slow down some of its operational efficiency initiatives with lower potential benefit to consumers it will use those resources to continue full steam ahead with its pro-competition initiatives. The criticisms of Mrs Melhuish, Mr Leyland and Dr Bertram require a fuller response, which is the focus of this paper.

4. Mr Leyland, in particular, has long supported a proposal to establish a single entity to directly set wholesale electricity prices and centralise generation investment decisions. This would be done by issuing long-term contracts to generators currently operating in the market and to hold tenders for the provision of new generation capacity. Dr Bertram and Mrs Melhuish have proposed changes to the Code that determine how the wholesale market operates. All of their proposals, and some others that have been aired, could be implemented by the Authority under its current legislation by changing the Code.

5. The reason the Authority will not be progressing Code changes along the lines argued for by the critics is that it does not believe they are consistent with its

statutory objective. More specifically, it does not believe they will promote the long-term benefit of consumers.

6. I believe it is appropriate for me to use this regular breakfast briefing to stakeholders to discuss the economic reasoning behind the calls for radical changes and explain why implementing them would be contrary to the long-term interests of consumers.

Myths about spot market pricing

7. The easiest criticism of the current market Code to deal with is the claim that generators should be paid on the basis of the prices they offer to the wholesale market. Under the current Code all generators are paid on the basis of the highest offer required to satisfy demand, called the **market clearing price**. Critics claim this results in most generators being paid more than the minimum they need in order to produce, and often for hydro and wind generators, much more. As a result, critics allege, consumers end up paying too much for electricity. In their view, the Code should be that each generation plant is paid its offer price rather than the market clearing price.

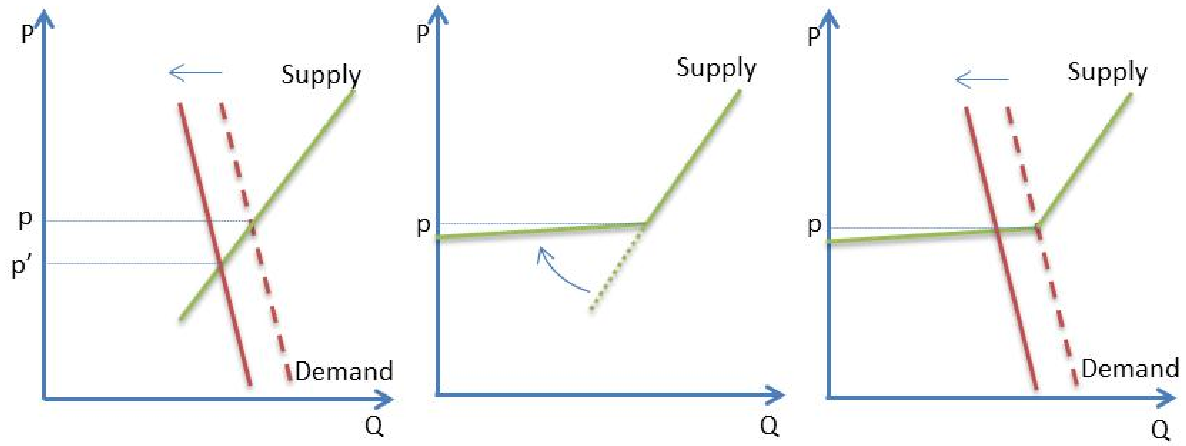
8. But it is easy to see that if the Code was changed in this way generators would quickly adjust the way they set their offers. In order to maximise their returns they would estimate the highest price needed to fully satisfy demand and, if they are happy to be dispatched at that price because it is above their actual marginal cost, they would pitch their offer at just below that price.

9. If a generator over-estimates what the market clearing price will be, it will not be dispatched. If the generator has lower marginal cost than another one that offered at a lower price and was dispatched, there will have been out-of-merit dispatch. In other words, a pay-as-offered market will result in higher cost generation operating than is necessary, which will be a cost to society. Consumers will ultimately bear this cost and so a pay-as-offered arrangement is detrimental to the long-term benefit of consumers.

10. Moreover, since under a pay-as-offered Code, generators will try to offer at just under what they estimate the market clearing price will be, provided this is above their actual marginal cost, the outcome would be that the supply schedule would not fall away to zero as volume falls as it does under the current Code. As a result, any unexpected fall in demand will result in a higher price for consumers (and generators) than would be the case under the current Code. The current Code encourages generators to offer at their actual marginal cost, no matter how low that is, and this benefits consumers. Once again, a pay-as-offered Code would lead to outcomes detrimental to the long-term benefits of consumers.

Figure 1: stylised example of uniform versus pay-as-offered spot pricing regimes

Current arrangement *Pay-as-offered arrangements*



11. Generators with offers below the market clearing price do not earn profits equal to the difference between their offer price and the market clearing price at which they are paid. If offer prices are based on marginal costs, as they usually will be, generators need to earn more than these in order to cover their fixed costs over time. These costs are largely the return on, and return of, the capital they have invested in their generation plant. If generators only ever received payment for their variable or marginal costs there would not be parties willing to invest in generation equipment. The shortages of electricity that would result would not be a benefit to consumers.

12. The consequences for renewable generation appear not to have been thought through by the proponents of pay-as-offered pricing. Most renewable generation is inflexible, or has a high component of 'must-run' to it. For example, wind generation needs to run when the wind is blowing, hydro generation often needs to run due to minimum flow and river-chain constraints, and geothermal generation typically has a very limited ability to vary output.

13. Under the current wholesale pricing arrangement, these plants can offer at very low prices to ensure dispatch to avoid spilling hydro, wind and geothermal energy but still receive an adequate capital return if efficient because they will be paid at the market clearing price. In contrast, under a pay-as-offered pricing regime there would be either much more inefficient spilling of hydro, wind and geothermal energy or the commercial viability of renewable generation would be harmed, and further investment in it limited or absent.

14. This is because under pay-as-offered the offer prices for renewable generators would generally be well above their marginal costs in order to ensure the price paid covers the cost of capital, but this will tend to result in inefficient spilling; i.e. spilling energy when it would have been cheaper for society to use it to produce electricity. If, however, the offer price was lowered to marginal cost to

avoid inefficient spilling, the return to the generator, which would be based on this low offer price, would generally be substantially below full costs of production, including capital costs.

15. If the Authority adopted pay-as-offered, the result would be either increased inefficient spilling of renewable energy from existing plants or a severe constraint on further investment in renewable generation, even if it would be efficient to do so. The Authority does not believe this outcome would be of long-term benefit to consumers.

Myths about the value of water

16. Another criticism of the wholesale market is that prices tend to be high when there is a drought and water is scarce, even though hydro-generators do not pay for the water that runs through their turbines; it is free to them. Since consumers are paying for costs that are not actually paid by the generators the claim is made that the system is unfair to consumers.

17. It is true that generators do not generally pay for the water that goes through their turbines and, as a result of gravity, water freely flows down rivers and into reservoirs and through turbines without requiring costs to pump it. However, what matters for economics is not what a single producer pays but the opportunity cost to society of the resources used. The opportunity cost of using water to generate electricity today is the value of using it at some time in the future to generate electricity, or its value in some other use, such as, irrigation, recreation or conservation of the environment.

18. Water has no value in an economic sense when it is so abundant that there are no constraints on the use of water now or in the future in any activity. Clearly, especially during a drought, water has significant economic value and the deeper the drought the higher the value is likely to be. The costs to society of running out of electricity in terms of discomfort and lost production are very high. Electricity is an essential element of modern life and economic activity.

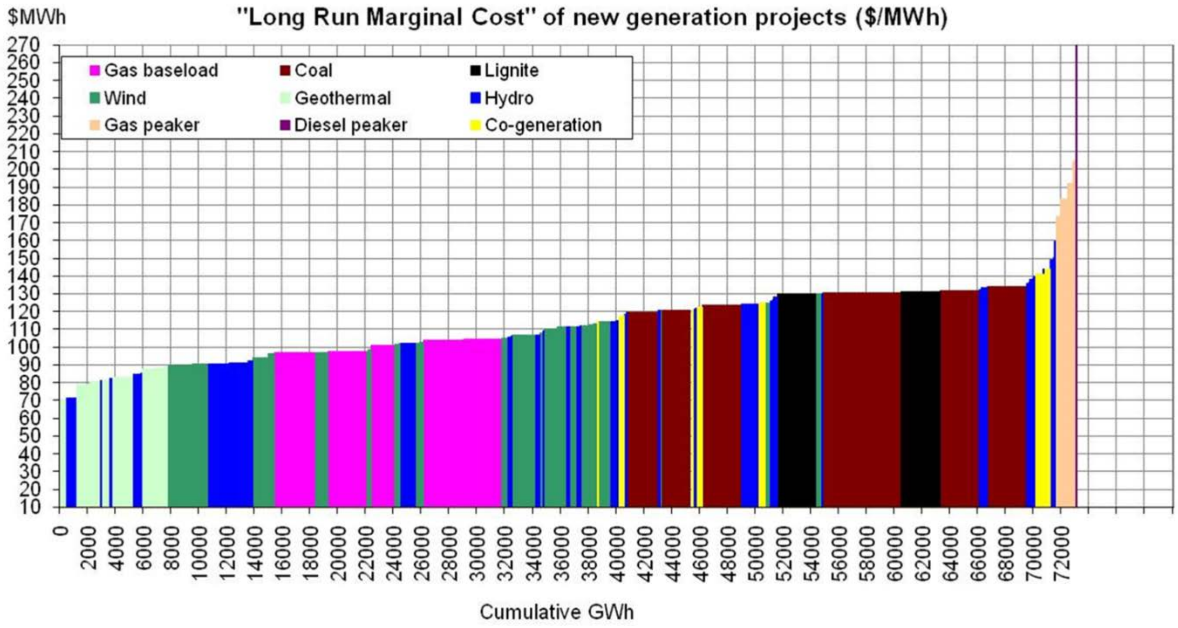
19. What the current wholesale electricity market does is reflect the market consensus view of the opportunity cost of water at each point in time. This provides economic signals to parties able and willing to reduce their power consumption to do so when water is scarce and signals to those with generation not dependent on hydro flows to increase production. This is particularly important given the heavy dependence New Zealand has on hydro-generation, the high variability of the timing of river flows and the low average storage the country is able to economically sustain in view of its steep topography.

20. A wholesale market that did not signal the scarcity of water in prices would quickly drive the country to reduce its dependence on hydro-generation and rely upon other sources of energy, such as, fossil fuels. Replacing existing hydro-generation plants with new (non-hydro) plants would be a very costly reorganisation of the electricity industry and contrary to the long-term benefit of consumers. The alternative is periodic and costly shortages of electricity that are also contrary to the interests of consumers.

21. Hydro-generators do not currently have to pay for water but the wholesale prices incorporate the opportunity cost of water. This does not mean, however, that hydro-generators are making super-profits under the current market. The capital cost of hydro-generation is much higher than, for example, a gas-fired turbine. The operating costs are the other way round, with the gas-fired plant more expensive than the hydro plant.

22. Currently potential investors decide when, where and what type of generation plant they invest in. They try to do this to maximise their returns. If they get it wrong, the losses that result are borne by their shareholders, and not consumers. In such a situation, if hydro-generation had a distinct total cost advantage over other types of generation because its fuel – water – is free, one would expect to see all new and replacement capacity to be hydro-generation. This is not the case. In fact, only the more productive hydro-generation sites are cost competitive with other options, including gas, wind and geo-thermal. There are no super-profits for hydro-generators from their fuel being free. It is offset by the cost of capital to build dams etc.

Figure 2: the long-run marginal cost (LRMC) of generation rises over time (unless there is a major gas find or a major technology break-through)



Source : MBIE

The Wolak report

23. One serious criticism of the current market is that generators effectively operate a cartel and are able to manipulate their offers into the market so as to extract super-profits at the expense of consumers. Those promoting this criticism usually refer to the 2009 study by Professor Frank Wolak for the Commerce Commission. They claim this proves that between January 2001 and June 2007 the four largest generators used market power in dry years to earn $4.3 billion excess profits from the wholesale market.

24. The first point to note is that operating a price fixing cartel is illegal in New Zealand under the Commerce Act. The penalties available are very high. The Commerce Commission is vigilant and operates a scheme that incentivises parties to inform on any other participants in a cartel. The investigations the Commission has undertaken to date have not found any activities in the wholesale electricity market that have warranted prosecution.

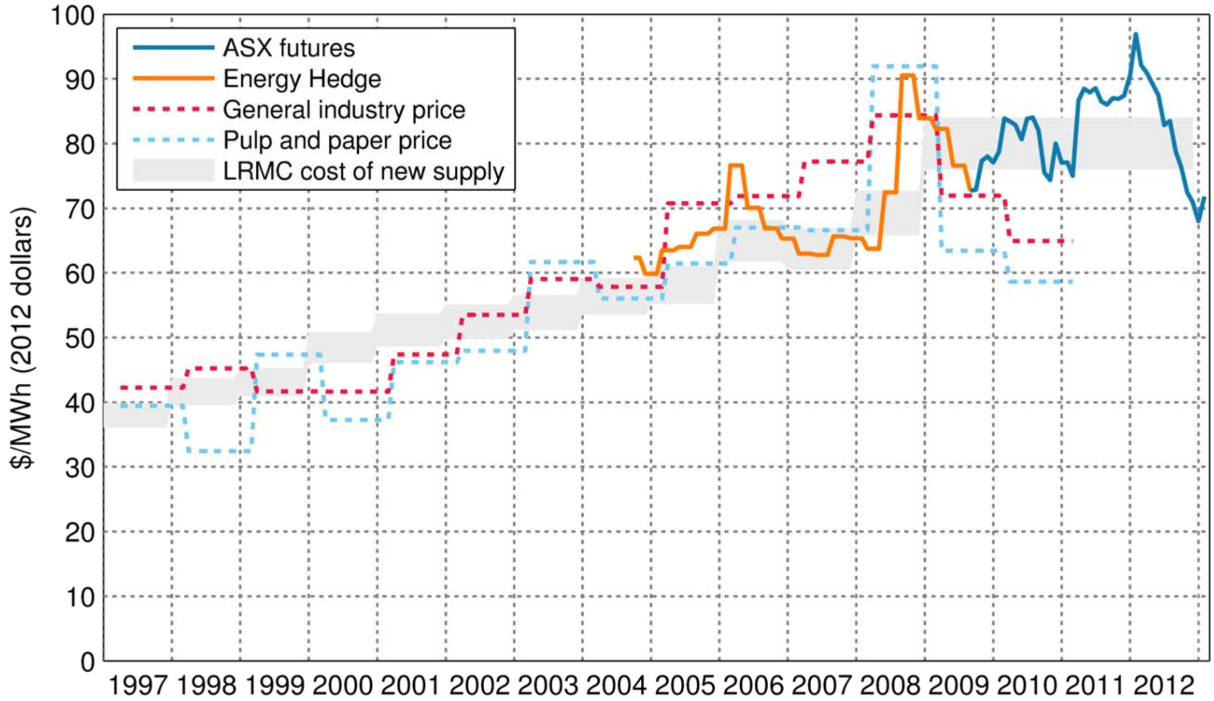
25. The second point is that claims made by Professor Wolak and those drawing upon his report were considered at considerable length and in considerable detail by the Ministerial Review of the Performance of the Electricity Market I chaired in 2009. The Ministerial Review received no less than three peer reviews of Professor Wolak's report and some members also held a telephone conversation with him.

26. The Ministerial Review noted that commentators had raised very serious reservations about the Wolak Report. The main factors being:

- underestimation of the opportunity cost of hydro storage, that is the value of water preserved for later use
- underestimation of the availability and opportunity cost of gas, particularly in the light of the decline of the Maui gas field
- the ‘competitive benchmark’ price based on short run marginal costs used by the report to calculate market power rents is not sufficient to cover the costs of building new capacity and ensuring security of supply. The additional costs of, for example, payments to generators to provide capacity have been missed from the calculations
- the analysis is done in hindsight, and assumes perfect foresight on the part of decision-makers, with no allowance for the uncertainties parties face in the real world regarding future demand, plant availability and hydro inflows
- the analysis uses actual demand to estimate the competitive benchmark price in dry years, which ignores demand response to high wholesale prices and biases the competitive benchmark price in the study downwards
- detailed analysis has not been done to establish that any excessive prices in the wholesale market have been passed on to consumers. Any effects may have been merely wealth transfers among generators.

27. The Ministerial Review also compared contract prices over the period 1998-2008 with the estimated cost of new supply based on production from a new combined cycle gas turbine as a surrogate for the long run marginal cost (LRMC) and found the two corresponded to one another fairly closely. The following figure presents similar data, updated to 2012. The ASX futures price has been added. This is the market’s expectation of future spot prices.

Figure 3: wholesale electricity prices are largely in line with LRMC



28. The data very strongly suggests that wholesale prices were accurately reflecting LRMC and led the Ministerial Review to conclude from the data for the period to 2008 “there is no clear evidence of the sustained or long term exercise of market power.”

29. In short, the Ministerial Review did not accept the claims of Wolak and those who draw upon his report to assert the market is open to sustained or material manipulation by generators exercising market power. The $4.3 billion of excess profits was not accepted.

30. The members of the Ministerial Review’s Electricity Technical Advisory Group that signed off the report had no reason to favour generators. None of them worked for a generator. In fact, none of them was currently employed in the electricity industry. The wide range of recommendations for change they did make also demonstrates they were not wedded to the status quo.

31. There is another good reason to reach the conclusion about Wolak and the $4.3 billion that the Ministerial Review reached. If, over a period of three dry-years between 2001 and 2007, four generators had been able to extract $4.3 billion in the wholesale market by exercising market power why did TrustPower remain a net retailer and Todd Energy not expand its generating capacity significantly? Neither TrustPower nor Todd’s could be considered short of the capital or the expertise to expand and there were no obvious barriers to entry. The clear implication is that they did not judge there was super profits being

made by generators.

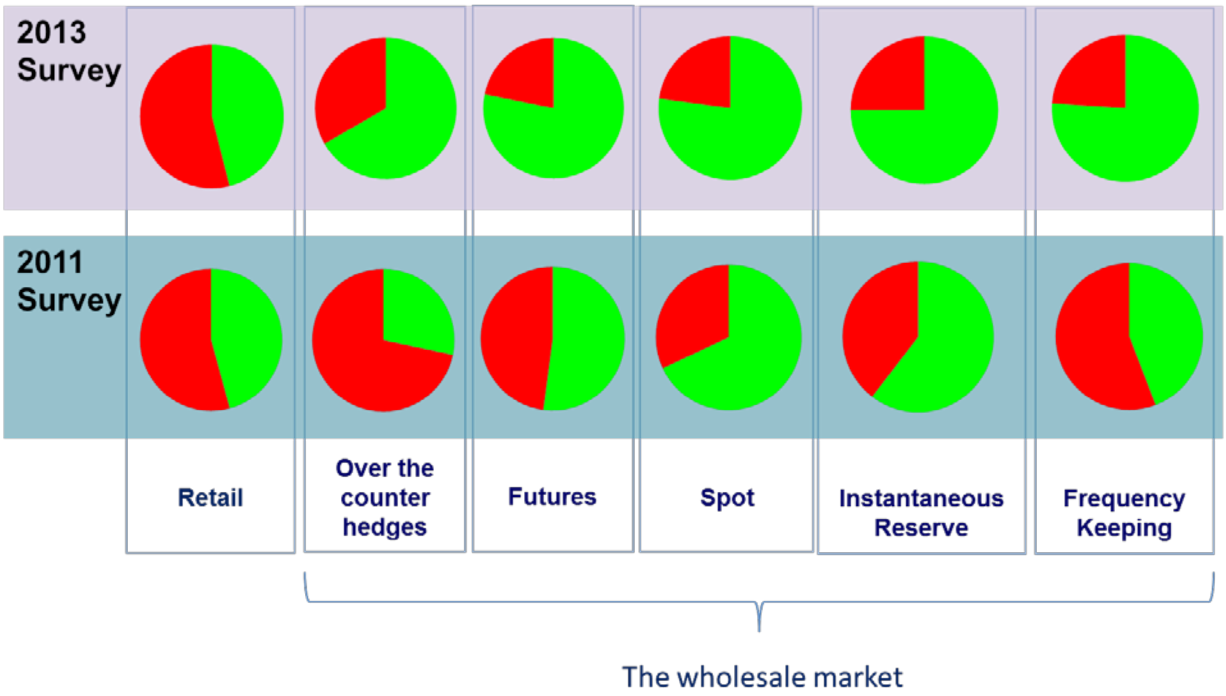
32. The probable reasons the analysis of Professor Wolak went astray are:

- preparation of the report was undertaken in isolation from the New Zealand industry
- the objective was to identify anti-competitive behaviour, without regard to market design
- the research appears to have been shaped by a United States perspective, where:
    - typically there is a separate capacity market to pay the capital costs of plant, so the expectation is that wholesale market prices will be close to SRMC
    - generation is predominantly thermal and so it is possible to observe the prices of inputs that go into SRMC. This is not possible for water, wind and geothermal energy, which are very important components of the New Zealand system
    - wholesale prices are typically capped at a relatively low level so high prices were seen as due to market power.

33. The Ministerial Review did, however, conclude that “there is some scope for the exercise of short term market power in the [wholesale] market.” and made recommendations designed to deal with these situations. The Electricity Authority has acted on all these recommendations, which related to developing a transparent hedge market, and is currently considering with the assistance of the Wholesale Advisory Group whether further measures may be of long-term benefit to consumers.

34. The Ministerial Review also found that some aspects of the ancillary markets to the wholesale market – frequency keeping and instantaneous reserves – could be improved. The Electricity Authority has implemented these changes, or is in the process of doing so. Stakeholders’ views about the competitiveness of various markets bear out the improvement that has been achieved recently. The colours in the pie charts below indicate the proportion of survey respondents that believed each electricity sub-market was competitive (green) or not competitive (red).

Figure 4: stakeholders much more positive about competition in the wholesale parts of the electricity market – only the retail market showed no improvement



The consequences of removing windfall profits

35. A further criticism of the wholesale market is that the general rise in wholesale prices has led to windfall profits for generators with existing plant that was built when equipment prices were much lower and this is unfair to consumers. According to these critics, consumers should be able to buy electricity produced by old plant at prices based on the plant's depreciated historic cost and current fuel and other operating costs. Sometimes this is expressed as wholesale electricity prices should reflect average costs of production, not marginal costs.

36. In some commentaries the notion of windfall gains has been mixed up with the notion of market power and the criticisms based on Wolak. The two are quite separate. Windfall gains (and losses) can, and often do, occur in any competitive market. They can also occur in uncompetitive ones, although the ability of producers to exercise market power may, in fact, help insulate them from normal market consequences. No one can force a monopoly, for example, to scrap its existing plant and equipment and adopt new cheaper processes, whereas competition can have this effect.

37. Windfall profits and losses can arise whenever price changes are unexpected. If the changes are expected they get built into current prices or asset values immediately and there are no windfall changes after these adjustments have occurred.

38. In an economy, windfall returns provide incentives for parties to find new and more valuable uses for existing assets and resources to capture the resulting windfall gains. They also provide incentives for parties to avoid investing resources into activities without a future so as to avoid the resulting windfall losses. In other words, windfalls are important for innovation and allocative and dynamic efficiency. The cultivation of these is of considerable long-term benefit to consumers.

39. It is possible to run a regime in a regulated market in which producers do not receive windfall returns from changes in the value of assets used in production. The most straight forward way to do this involves setting the maximum allowed revenue (MAR) of the regulated entity on the basis of the depreciated **historic** cost of its regulatory asset base (RAB), instead of basing it on its depreciated **current** cost.

40. However, the present value cost of new supply under such a regime will be very similar to what it would be for new supply under a regime in which MAR is based on depreciated current costs, and the producer receives windfall gains from unexpected increases in asset values and bears windfall losses. The reason for this equivalence result is that investors will tend to want a similar return irrespective of whether the enterprise's MAR is set on an historic cost or current cost basis. There is no free lunch. If the rules preclude an investor from benefiting from windfall gains (or losses) the returns they will require will have to compensate them for their expectations in this regard.

41. In fact, in the short-term, prices of new supply may be higher under the historic cost regime with the investor not subject to windfalls than under the current cost regime with them bearing them. This is because asset values are generally expected to rise over time and so investors are willing to accept lower cash returns in earlier years for significantly higher cash returns later under the current cost regime.

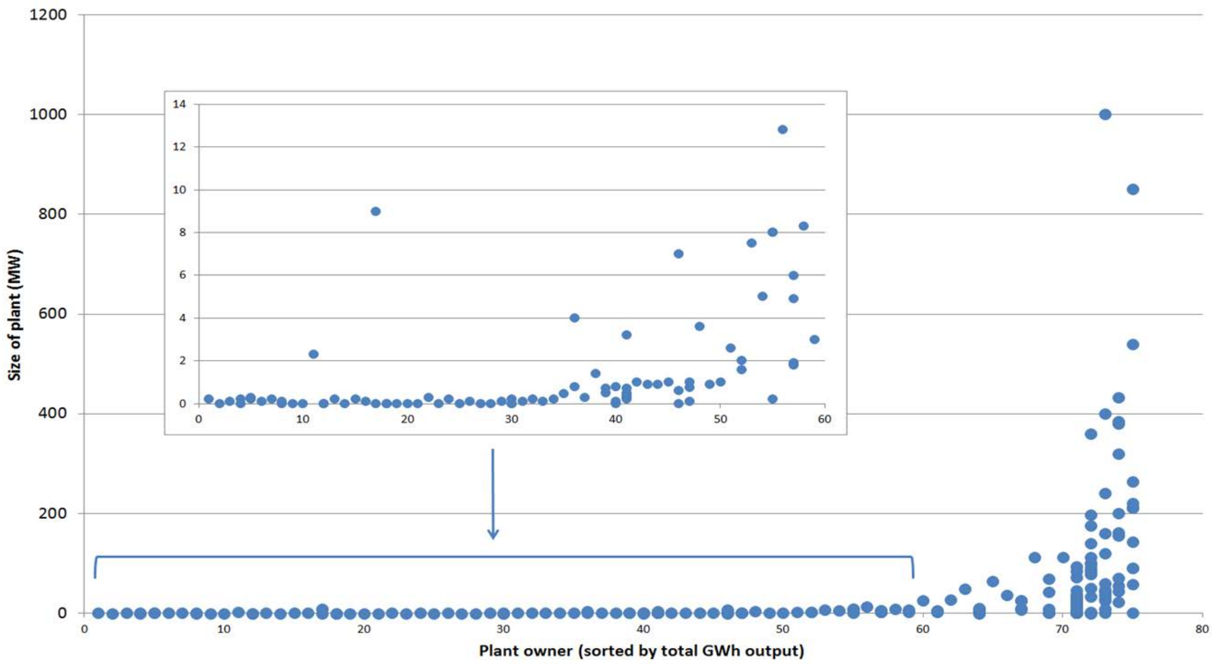
42. It is well recognised by regulators that care needs to be taken to ensure producers and consumers are not disadvantaged if the basis on which MAR is set in a regulated market is changed between current costs and historic costs. When shifting from a current cost to an historic cost basis it is usual for the regulator to deem the current cost of the RAB to be the opening historic cost.

43. Transpower, for example, shifted its RAB to historic cost valuation in 2008. It made this switchover by adopting its 2008 valuation as its opening historic cost valuation. To do otherwise, would involve ex post transfers of wealth and, in the case of transfers to consumers, is likely to have an undesirable chilling

effect on the willingness of parties to invest. This is definitely not a long-term benefit to consumers.

44. In the wholesale electricity market, prices are determined by competition between generators offering to supply and these offers being matched to demand. The values of the different generation assets are driven by market prices and not vice versa. The wholesale market is not one in which a regulator exercises price control because it is a workably competitive market with over a dozen grid-connected players on the supply-side and five reasonably large players. There are more major generators in New Zealand than there are major banks, petrol companies or telephone providers. There are, in addition, another 70 generating entities in New Zealand.

Figure 5: there are 75 generating entities in NZ (13 are grid-connected)



45. In order to remove past windfall gains from existing generators it would be necessary to make decisions to transfer wealth from them to consumers and bear the undesirable chilling effects this would have on the willingness of parties to invest in future in electricity and probably other sectors.

46. In order to remove future windfalls from new and existing generators it would be necessary to replace the current competitive market structure with a regulated one. Under the simplest form of this regime each existing generator's MAR would in future be calculated by the regulator using the deemed depreciated historic cost to value its RAB and set prices. In other words, the generator's depreciated current cost valuation, at the time set when the regime was

changed, would be deemed to be the initial depreciated historic cost of its RAB. For new generators, the regulator would calculate MAR using actual depreciated historic cost at the time of construction to value its RAB and set prices.

47. As already explained, a change to such a regulatory regime and the adoption of historic costs may well raise prices in the short-term, not lower them, although by adopting more complex approaches to estimating depreciation this could be overcome. The change would also mean that generators would be sheltered from not only windfall gains but also windfall losses as might happen if, for example, wholesale electricity prices were to fall due to excess capacity. These windfall losses would fall on consumers under the regulated regime.

48. It is always hard to predict what is going to happen to prices and asset values in the future. However, because excess capacity in the generation market appears likely over the next few years, the next few years appear to be the wrong time to switch from the current regime to a regulated one if the objective is the long-term benefit of consumers. This is because consumers are likely to end up bearing windfall losses and generators are likely to escape them. This point is additional to the inefficiencies that would flow from replacing the current competitive arrangements by ones in which prices and/or returns are regulated.

49. A variant on the previous criticism is that most of New Zealand's older hydro-generation assets were built a very long time ago by the government (by the NZ Electricity Department, or NZED) and have been fully depreciated and paid off. According to those promoting this criticism, there is no need to include any payment for the cost of capital in the price of electricity produced from these plants.

50. The problems with this reasoning are that NZED's generation assets were transferred to SOE's and/or privatised on the basis of their earning capacity at the time of the transfer. Moreover, they were transferred on the basis that the new owners would receive the benefits of any unexpected increases and bear the costs of any unexpected decreases in electricity prices subsequent to the transfer.

51. To now determine that the return on capital will be set by regulators, and windfall gains and losses will not be permitted, breaches the implicit regulatory bargain entered into by the Crown when it transferred the assets. It can be open to a regulator to do such a thing, but the consequence would be to have a chilling effect on investment in the electricity sector, and probably elsewhere. This would not bring long-term benefits to consumers.

The myth of inflated asset values

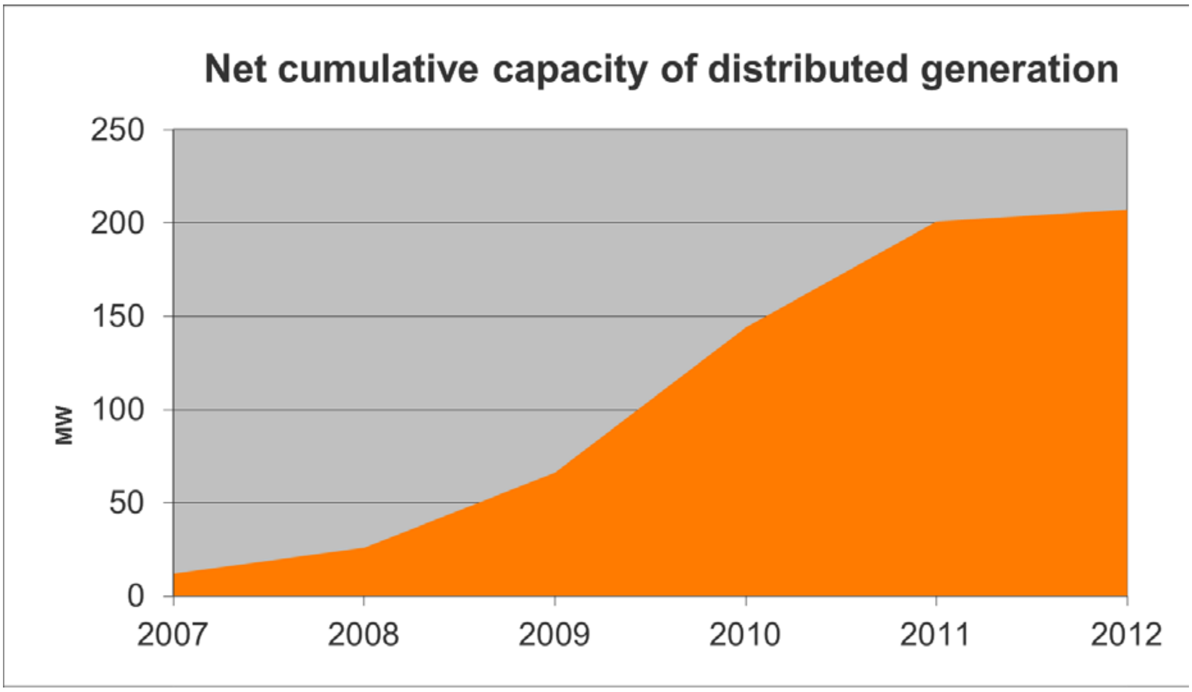
52. Another criticism of the current arrangements is that generators have been revaluing their assets and using the higher asset values as the justification for increasing prices. This is a game that some New Zealand regulated entities with market power have engaged in. Worse still, there have been incidents when the regulated entity has not counted the increase in asset values as part of its overall returns when resetting its prices and has, in this sense, double dipped.

53. This accusation cannot be legitimately applied to generators, however. They are not regulated entities with market power setting their prices off their own asset valuations. There are five major generators and a whole lot of others as well, and the barriers to entry into being a generator are low. For example, several iwi with initially very limited capital resources have managed to enter the market and thrive. There has been a very large increase in distributed generators in recent years.

54. The generation market is workably competitive and, in such a market, prices are set by the interplay of supply and demand. Prices determine the returns parties receive for output and returns determine asset values and not vice versa.

55. The claims that generators are using asset revaluations to ratchet up prices are based on confusion over what determines asset values in a regulated market with what determines them in a workably competitive one.

Figure 6: the total capacity of distributed generation has grown rapidly in recent years



The recommendations of the Ministerial Review

56. The Ministerial Review found that the wholesale market was generally performing well but it made a number of recommendations to further improve its operation:

    a) phase out the Whirinaki diesel-fired back-up plant and the reserve energy scheme based on it
    b) clarify terms of access to 'reserve water' in lakes Hawea and Pukaki
    c) restructure SOE generation assets and require them to enter into virtual swaps
    d) require retailers to make payments to consumers in the event of a public conservation campaign or enforced power cuts
    e) introduce scarcity pricing
    f) facilitate development of a hedge market for energy
    g) improve market risk disclosure
    h) facilitate greater demand side participation in the wholesale market
    i) introduce a transmission hedging product.

57. The first seven items have been implemented, either by the Authority or other parties, and the last two items will be implemented within the next few months.

58. The proposals to change the wholesale market Code that have arisen from the various criticisms would not provide long-term benefits to consumers.

The centralised decision making approach

59. This applies also to the proposal to establish a centralised decision maker to enter into long-term contracts to purchase electricity from generators currently operating in the market and to hold tenders for the provision of new generation capacity.

60. This proposal is not new. It was among the options considered in the early 1990s when the establishment of a wholesale electricity market was first proposed. It also arose when the market was reviewed in 2000-01, following the change in government in late 1999, and again in 2006, after a string of dry years had made some politicians unsure the market would provide the investments necessary to ensure reliability. Finally it was included among the numerous submissions made to the Ministerial Review in 2009. On each of these previous occasions it has been scrutinised and found wanting in terms of what would be of long-term benefit to consumers.

61. A reason the proposal has resurfaced so prominently recently appears to be a belief among some of those promoting it that Wolak identified approximately $4.3 billion (or $650 million per year) of super-profits were being received by generators. This has led some to conclude electricity charges for consumers could be reduced by several hundred million dollars a year relatively easily.

62. As explained previously, the Wolak research is contrary to more credible evidence. There is no capacity to extract from the wholesale market a half billion dollars or more a year of super profits. Nor are there material super profits falling to generators by other means. The only way to extract anything like these sums from the wholesale market is by ex post changing the regime under which investors have invested in generation in the past and the expropriation of their wealth. It is not possible to both reduce wholesale prices by in aggregate a half billion dollars or more a year and provide generators with an appropriate return on their investment.

63. Regulators are always able to transfer wealth, but if they do so it has to recognise there will be a cost. The cost will be in the willingness and terms on which parties will invest in generation capacity in the future and in other sectors of the economy. Given the size of the expropriation required to raise, say, $500 million a year would be about $7 billion, the chilling effect on investment in New Zealand is likely to be large, widespread and long lived. Either the government will be forced to build future plants (and many other assets) or shortages of electricity (and other services) will be likely.

64. The centralised decision maker arrangement could be introduced without widespread expropriation but it would be less efficient than the current

arrangements for several reasons.

65. Firstly, it would require a large bureaucracy and an army of generator staff supported by consultants to determine the appropriate amounts to pay existing generators to cover their operating and capital costs. I estimate that for the approximately 110 generator-class market participants and their 300 plus plants it would take at least 300 analysts and lawyers five years to set up the system ($180 million)[1] and after that 150 people to run it ($18 million a year). A major cost would be working out the opportunity cost value of water in each storage dam.

66. In addition, the new arrangement would require the central contract buyer and potential investors in generation to have significant expertise and resources to conduct tenders for future capacity. I estimate 50 analysts and lawyers would be required for this at an annual cost of $6 million.

67. Moreover, there will be a need for extensive negotiations with retailers over their contracts with the single contract buyer and there may also be the need for monitoring of the split between retail and generation activities within the one company. I estimate a further 50 analysts and lawyers would be required for this at an annual cost of $6 million.

68. Finally, but probably most importantly, any costs resulting from any planning errors will be borne by consumers and not producers and are likely to be much greater because of the difficulties of monitoring the performance of bureaucrats. The likelihood is that the surplus/shortage cycles experienced by New Zealand when NZED was the sole producer of wholesale electricity will be repeated with a deleterious effect on social welfare and the performance of the economy.

69. Experience in other countries – Brazil, Mexico and South Korea, for example – shows the central decision maker approach to electricity has not been fully successful.

70. In Brazil the central decision maker has ended up paying more for electricity from old plants than the cost of producing electricity from new ones.[2] This clearly involves a wealth transfer to existing generators, and not away from them, and is obviously inefficient.

[1] The cost estimates are based on costs being on average $120,000 a year for each person. This is modest given the salaries, offices and support staff and operating expenses likely to be required for each person engaged. It is the standard figure used by the authority in its recent cost-benefit analyses.

[2] Rego, E.E. and V. Parente, "Brazilian experience in electricity auctions: …", *Energy Policy* 55(2013) 511-20.

71. In relation to Mexico the World Bank has noted that while the arrangement had succeeded in contracting extra generation capacity its "overall efficiency has been challenged, with some questions as to whether the risks of implicit guarantees are growing significantly, and if there are alternative schemes to develop the program more efficiently." [3]

72. In South Korea, the central decision maker has struggled to break even and satisfy demand. Industrial consumers were recently requested to alter their working hours to reduce pressure on electricity capacity. In August 2012 prices for consumers were increased by 4.9% in an attempt to reduce demand and return the sole buyer to profit. In January 2013 prices were increased on average by a further 4%.[4]

73. The claim by BERL that a reduction in electricity prices of the magnitude proposed by those advocating a central decision maker in New Zealand would create over 5,000 jobs and boost economic growth by $450 million is flawed. Only if the reduction in prices were to come from an improvement in efficiency of producing electricity could there be any uplift in overall economic activity; a wealth transfer cannot be expected to expand the total size of the economic cake.

74. In fact, given the inefficiencies of the central decision maker arrangement identified previously, the result will be to shrink the size of the New Zealand economy because more resources would be needed to operate the market than under the current arrangements for a less efficient economic outcome. This is a long-term dis-benefit to consumers.

Concerns about retail price inflation

75. The main reasons put forward for the central decision maker proposal or other Code changes around the wholesale market appear to be concerns about:

- the extent to which residential electricity prices have risen in recent years
- the perception that electricity prices have risen much faster in New Zealand than other countries
- the ratio of residential prices to industrial prices being high in New Zealand compared with other OECD countries

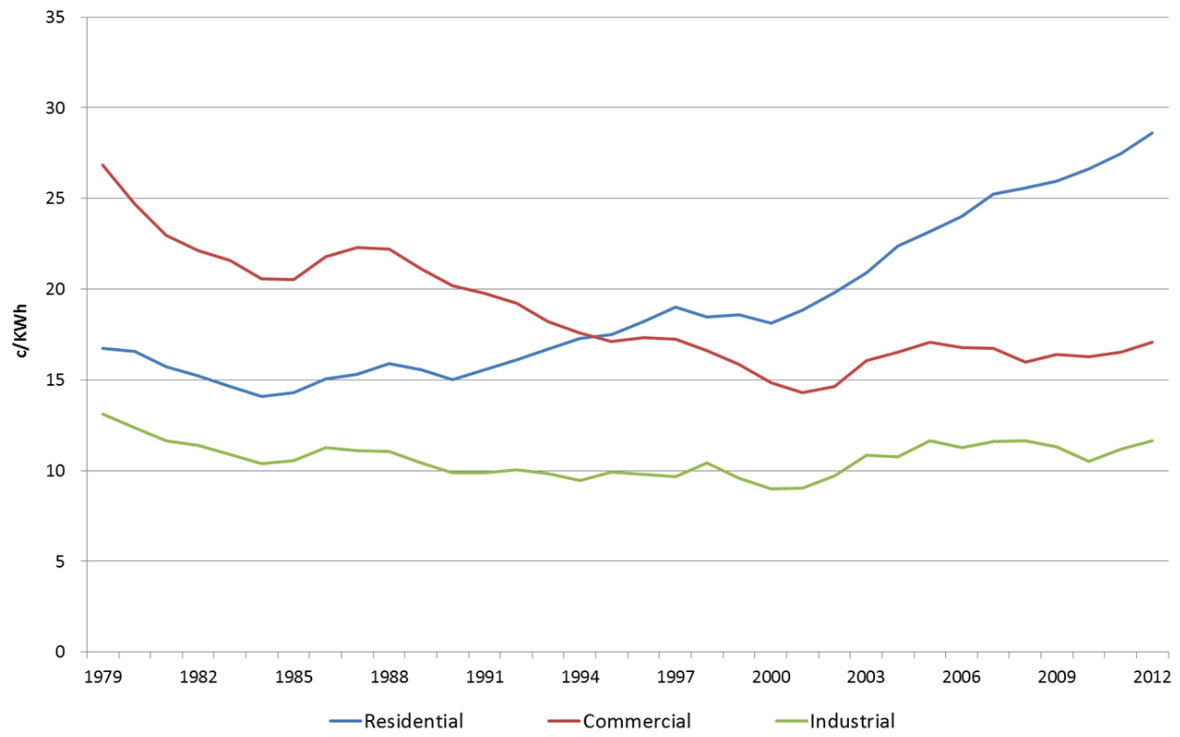
76. I will consider each of these in turn.

[3] World Bank, *Electricity Auctions: an Overview of Efficient Practices*, 2011, p. 57.

[4] See http://www.bloomberg.com/news/2013-01-09/south-korea-increases-power-prices-second-time-to-curb-demand.html .

77. The 2009 Ministerial Review I chaired was also concerned about the rate at which residential electricity prices had risen between 2001 and 2008. It noticed that while residential prices had risen appreciably slower than the rate of inflation in the years from 1997 until 2001 – when the wholesale market was first established - from 2001 until 2008 they had risen significantly faster.

Figure 7: real (inflation-adjusted) residential electricity prices have risen faster than for commercial and industrial consumers



Source : MBIE

78. The Ministerial Review also noted that residential prices had risen faster than prices for commercial and industrial users from 2001 until 2008. There are several potential factors contributing to residential prices rising since 2001.

79. Firstly, the wholesale cost of natural gas roughly doubled in this period as a result of the Maui gas field redetermination and the sourcing of new gas fields. Coal and fuel oil prices also rose. While thermal generation is nowhere near as important as hydro-generation for producing New Zealand's total electricity output, it is very important for producing the power consumed during peak periods of consumption. These occur on week-days in the morning and the late afternoon and early evening. Residential demand is concentrated in these peak periods of the day; in New Zealand it is demand from households that largely drives the peaks. In view of the importance of thermally generated electricity for satisfying peak demand, it seems reasonable that residential prices rose

sharply in real terms and much more sharply than prices for commercial and industrial consumers, whose demand patterns are typically flatter during the day.

80. Secondly, in 2004 the government introduced a requirement that retailers provide a low fixed charge option to customers, such that residential consumers using *less than* 8,000 kWh a year pay less on this option than they would on any other corresponding option. This regulation effectively requires a cross-subsidy from all high use consumers to low use consumers receiving the low fixed charge. The data upon which the residential price trends are based relates to the cost of electricity to residential customers using 8,000 kWh a year.[5] As more and more low use consumers took up the low fixed charge tariff option as time went by it was almost inevitable that the reported price of electricity to residential customers consuming 8,000 kWh a year would rise as retailers set standard charges to offset the increasing level of subsidies required under the regulations.

81. Thirdly, residential prices include the costs of transmission, and these costs, which are subjected to regulation by the Commerce Commission, have risen sharply in recent years to reflect the significant investment undertaken to expand the grid. It appears these cost increases have fallen disproportionately on residential consumers as industrial consumers have increasingly altered their peak consumption levels to minimise their share of transmission charges. The structure of charges, and particularly the introduction by the Electricity Commission of charges based on peak regional demand, has incentivised industrial and some commercial customers to respond in this way.

82. A fourth potential factor is that increases in distribution charges may have fallen disproportionately on residential consumers, as distributors have been changing their cost allocation models to unwind historical cross-subsidies in their charges.

83. The Authority is undertaking a detailed analysis of the drivers of residential electricity price increases that have occurred over the last three decades, to bring more clarity about these factors. We are hoping to publish the document later this year.

The focus needs to be on retail market competition

84. Although these factors go some way to explaining the trends in residential prices, the 2009 Ministerial Review did not think they were the entire story. It concluded there was insufficient competition in the retail market and made a

[5] http://www.med.govt.nz/sectors-industries/energy/electricity/prices/electricity-tariff-surveys/archive

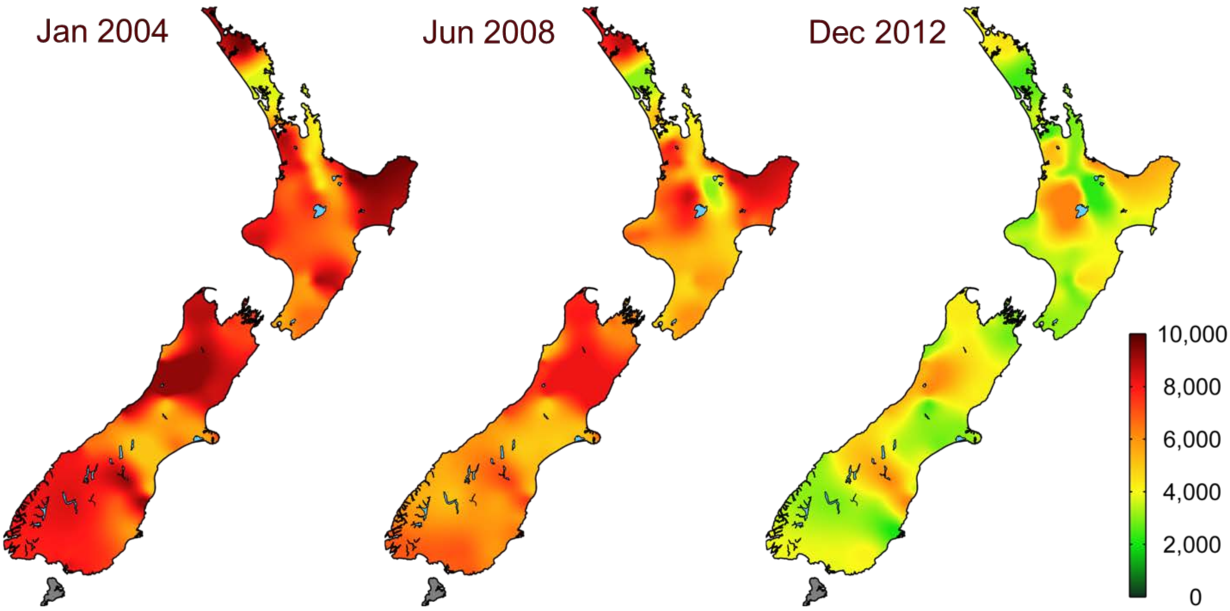
number of recommendations to improve competition:

- restructure SOE generation assets and require them to enter into virtual swaps to break up the close link between the location of a generator's plant and its retail base
- introduce a transmission hedging product
- facilitate development of a hedge market for energy
- allow line companies to provide electricity retailing services in their local areas, subject to some restrictions to ensure they did not discriminate against other retailers
- develop more standardised tariff structures
- develop more standardised use of system agreements
- encourage and support customer switching through:
    - shortening the timeframe of switching between retailers from 23 days to under 5 days
    - improving the Powerswitch website by requiring retailers to provide up to date information
    - funding a campaign to promote the benefits of comparing and switching electricity retailers.

85. All of these recommendations have been acted upon and implemented, except the transmission hedging initiative which starts next week.

86. The result has been a significant change in the structure of the retail market and in particular a reduction in the concentration of suppliers in each region.

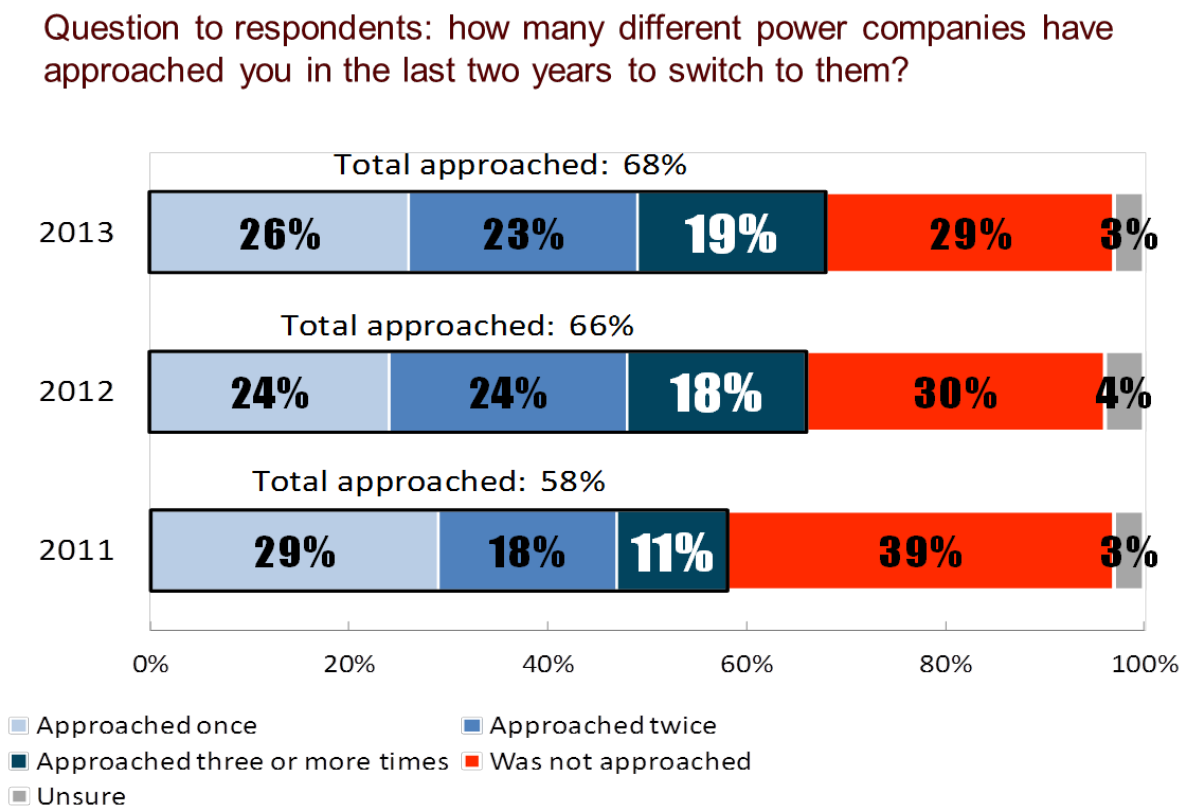
Figure 8: concentration in the retail electricity market, as measured by the Hirschman-Herfindahl Index (HHI), has continued to fall rapidly[6]



87. There have also been substantial changes in the conduct of market participants. More discounting to retain customers indicating they may change retailer. More direct marketing to households (see Figure 9 below). New products providing residential consumers with better information about their consumption have been introduced. There are also new tariff options starting to emerge that will allow consumers with smart meters to respond better to the price variations in the wholesale market, and off-peak prices for distribution, by varying their consumption during the day or week.

[6] The lower the HHI (the greener the colour) the more even is the market share of electricity retailers in the area and, in general, the more competitive is the market structure. The range is from monopoly (10,000) down to perfect competition (0).

Figure 9: since 2011 there has been a big increase in competition among electricity retailers for customers

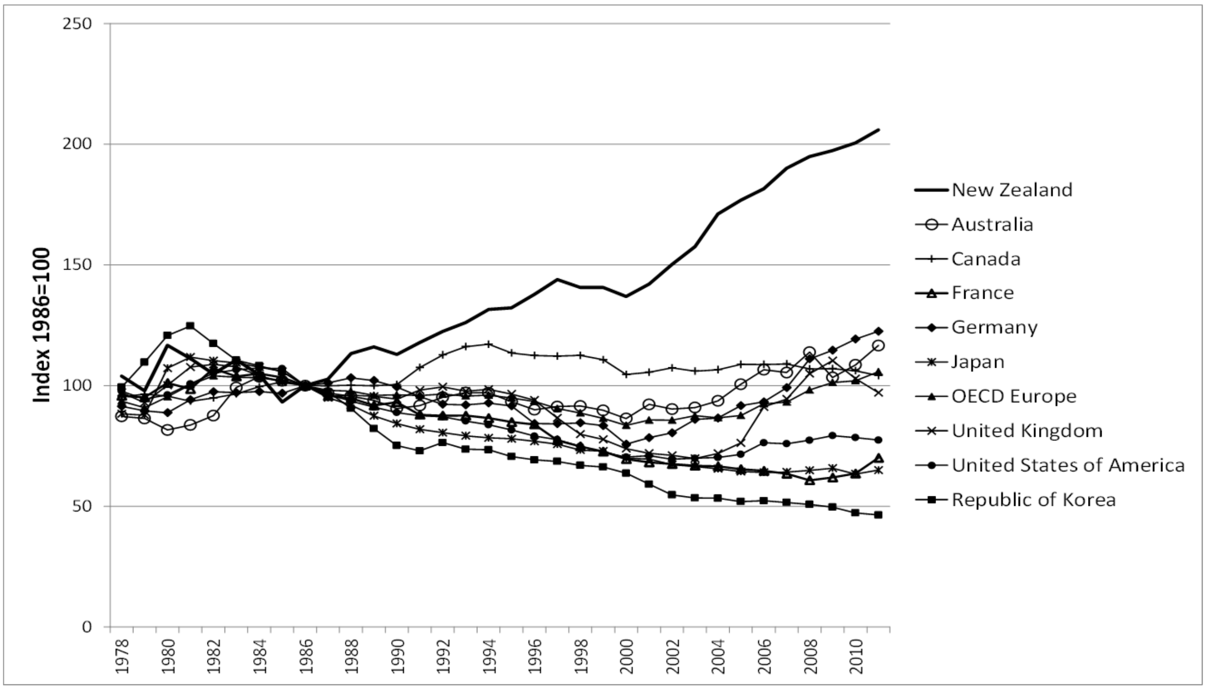


88. Progress in changing the competitive environment has been good in the two years and eight months since the Electricity Industry Act 2010, which embodied most of the Ministerial Review's recommendations, was passed. Changing market performance always takes time, however, and so there is more to do. For this reason the Electricity Authority will not be slowing its work on policies to promote competition.

89. The Authority calculates that on average residential consumers could save $175 a year by switching to the cheapest retailer in their area. Since retailers set their own prices, it is reasonable to assume that even the cheapest retailer in each area is making a satisfactory profit at the prices they are charging. A corollary is that increased competition in the retail market should be able to drive prices down towards the lowest cost provider. Greater competition should also lower to some degree the costs and returns of the current lowest cost provider. This suggests that increased competition in the retail market could over time yield gains of around $200 per household.

90. The perception that the rate of increase of New Zealand electricity prices compared with the rate of increase in other countries should be a matter of concern is largely based on the following chart produced by Dr Bertram.

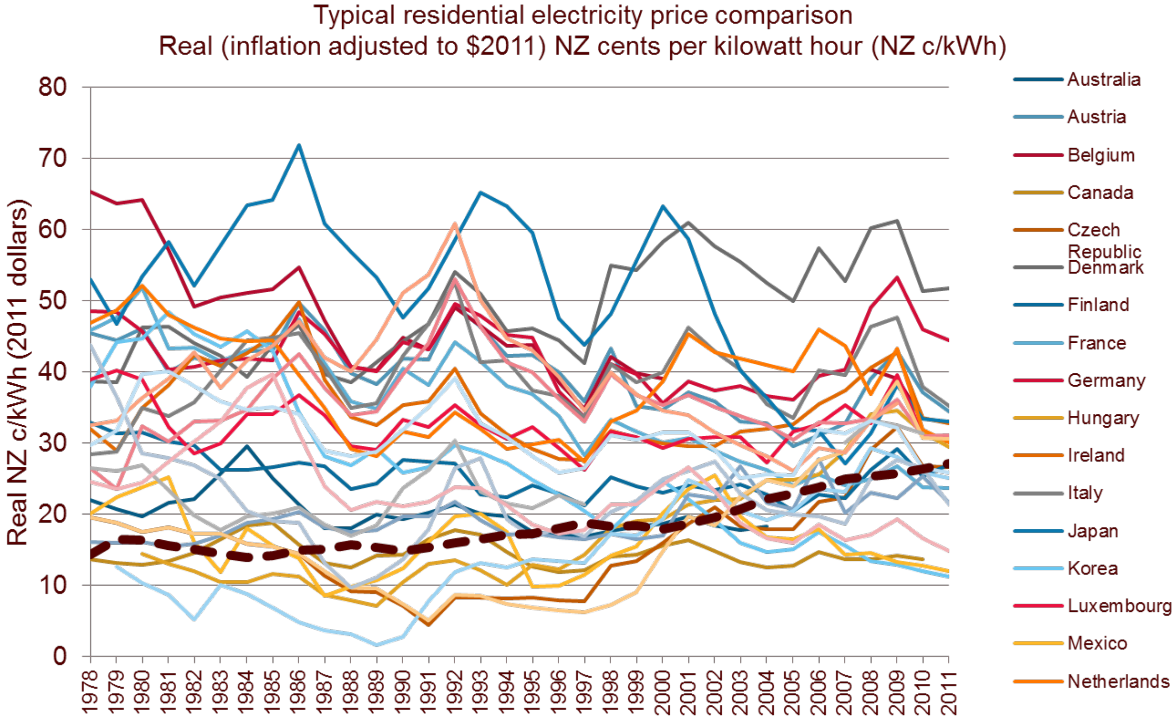
Figure 10: indices of electricity prices are misleading



91. This chart, however, measures residential electricity prices in terms of an index number and so removes any information about the absolute level of electricity prices in New Zealand compared with those in other countries.

92. The following chart shows the absolute levels. It shows New Zealand electricity prices were very low in the early 1980s, the base period for Dr Bertram's chart. In the early 1980s New Zealand had several years of a total price freeze. Electricity prices were subsidised by tax payers because NZED did not earn a full return on its investments and residential prices were subsidised by commercial users because of the political incentives on power boards. The NZ retail price is given by the thick dashed line in the chart below.

Figure 11: NZ residential electricity prices are about middle of the pack

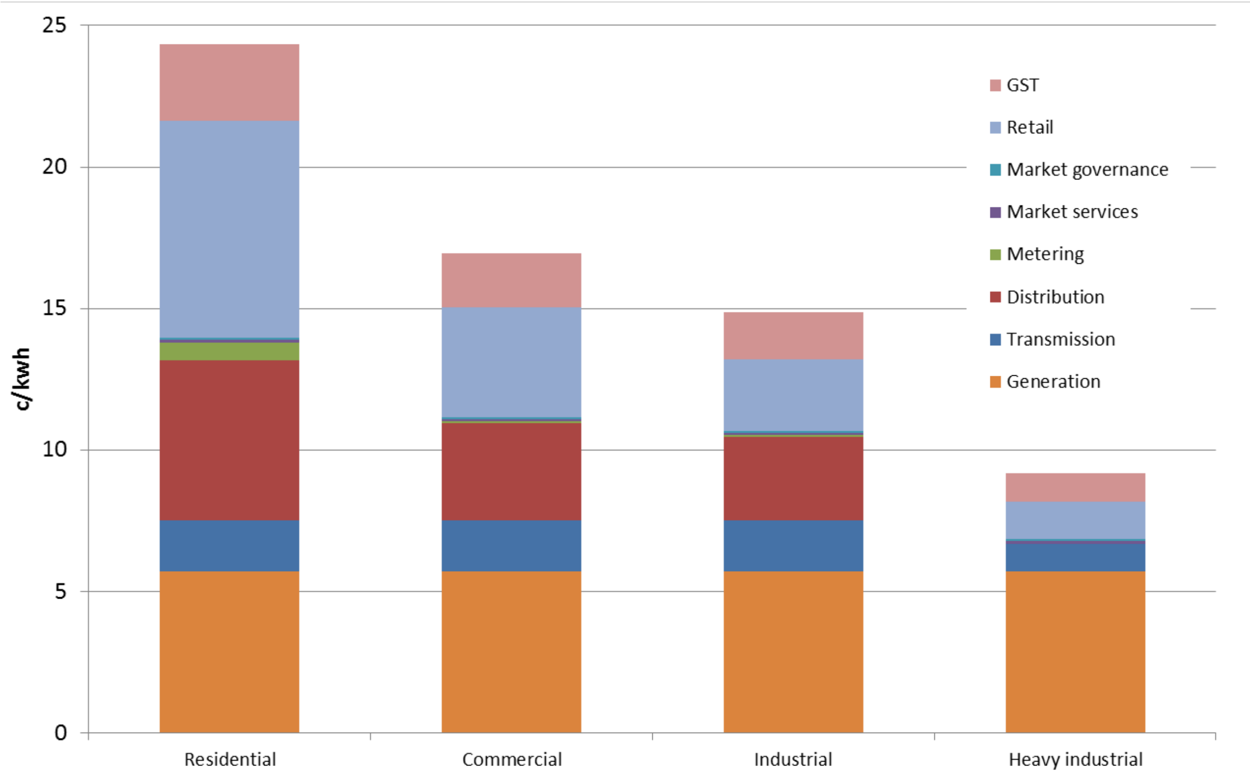


93. What this chart shows is that New Zealand residential prices were very low in real terms compared to those in other countries in the late 1970s and early 1980s but are now middle of the pack. This fact is hidden in the chart produced by Dr Bertram.

94. Finally, some have claimed that residential electricity prices are nearly three times industrial electricity prices is inexplicable. However, the Electricity Authority's Fact Sheet No 3 provides an explanation of the ratio through giving a detailed breakdown of the costs of electricity to four groups in the year ending March 2010. The four groups are residential, commercial, industrial and heavy industrial.

95. What the fact sheet shows is that the differential in the end charges to residential and industrial are explainable by GST at 15% being applicable to residential but reclaimable by other groups and differences in costs of retailers to serve, transmission charges, liability for distribution charges, metering costs and EA levies to operate and govern the market. Conclusions based on inadequate research are not a basis for sound economic policy.

Figure 12: different costs apply to different types of electricity customer



Source : MBIE / Electricity Authority

96. The reason that the ratio of residential to industrial prices is high in New Zealand is almost certainly due to the nature of our industrial users. The major industrial consumer is Tiwai Point aluminium smelter, which has a high constant load and as a result a low cost to service. It consumes about 14 per cent of New Zealand's electricity, and about 36 per cent of industrial load.

97. The other major industrial users are steel mills and wood processing and food processing plants. Again, these tend to have high steady loads. They also often use their own co-generation plants when prices are high in the wholesale market, thus lowering their average price well below other consumers. The New Zealand market is very efficient at signalling this to industrial consumers. In short, the relatively low industrial prices in New Zealand reflect an advantage of the current market, not a deficiency of it.

The Authority's focus is on retail market competition

98. The recent criticisms of the wholesale market are:

- based on a misunderstanding of economics (e.g. water is free) or

- propose remedies that are unlikely to achieve the desired outcome (e.g. adopt historic cost basis for paying for future generation capacity) or
- propose unilateral and *ex post* wealth transfers from producers to consumers that would have a chilling effect on investment in the electricity sector, and probably elsewhere in the economy.

99. The proposals to change the wholesale market Code that have arisen from the various criticisms would not provide long-term benefits to consumers.

100. This applies also to the proposal to establish a centralised decision maker to enter into long-term contracts to purchase electricity from generators currently operating in the market and to hold tenders for the provision of new generation capacity.

101. The current focus of the Electricity Authority is on increasing the level of competition in the retail market because it believes that by doing so significant benefits for consumers can be delivered over the next few years.