

Electricity market performance

2013 YEAR IN REVIEW



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Published March 2014

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The Electricity Authority's statutory objective is to promote competition in, reliability of supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers. This review outlines progress towards this objective during 2013.

A thriving retail electricity market

In 2013, competitive activity increased and broadened in the retail market. Consumers were offered a wide range of deals during 2013 as retailers competed for market share. These deals were often in the form of cash discounts on power bills. Anecdotal evidence suggests that many deals were not advertised but offered by door-to-door salespeople and through offers to customers to try to retain them when they indicated an intention to switch.

Our analysis of market structure shows that the retail market has continued the strong trend towards lower concentration. This is a sign that the market is becoming more competitive. Overall, there were more competitors in the market, and market share was more evenly distributed across the various players. Over 2013, smaller retailers' market share continued to rise at the expense of large incumbents.

Consumer switching and special offers

Behind this trend is the rate of switching in the retail market, which has continued at a very high level. An aspect of switching that has caught our attention this year is 'saves' – when a consumer initiates a switch, then cancels it, presumably because they receive a better offer from their original retailer. For individual consumers, this is a good outcome as they gain a better deal. However, for the market as a whole, it may have a detrimental effect on competition if it harms new-entrant retailers. The Authority has initiated a project to investigate whether this is the case.

Retail prices

Price matters for consumers, and in 2013, there was public and media criticism of the price of electricity in New Zealand. Ideally, we would compare price and cost to determine whether the market was efficient. However, all of the available pricing data is modelled on standard plans and average consumption. This data excludes much of the

competitive activity that we see in the retail market such as the non-advertised deals and discounts mentioned above.

To investigate prices, we measured the rate at which costs have increased and compared it with the rate at which prices have increased. We found evidence that competition has put pressure on prices. In a competitive market, prices should increase as costs increase. What we found with the retail market is that prices have increased more slowly than costs. This is an important result, especially as the price data is likely to be biased upwards as it does not include all available discounts.

We also analysed the cost to serve different market segments and found evidence that suggests that residential consumers drive costs in the system because of how they consume electricity. As a group, residential consumers tend to consume energy at the same time (consumption is concentrated during the morning and evening). This drives electricity system peaks and the consequent need for infrastructure to deal with these peaks. This analysis has showed that the cost to deliver energy to residential consumers is about 13% above the average cost of delivery to other consumers, suggesting we should expect retail prices for residential consumers to be above average costs.

More smart meters in 2013

Smart meters are important because they enable a greater range of services for consumers. In 2013, data from smart meters was made available directly to consumers through Mercury Energy's Good Energy Monitor, and Genesis piloted time-of-use pricing for residential consumers. We expect that these kinds of pricing plans and information will become increasingly available as smart meters continue to be deployed.

A vibrant hedge market

It was a year of records for the hedge market. Trading volumes on the Australian Securities Exchange (ASX) were at a record high in January, reaching 2000GWh in January. Uncovered open interest (UOI) is a measure of how much hedges are being used to cover spot market risk – it peaked late in the year at 3,650GWh.

A vibrant hedge market is important for consumers because it provides retail entrants with a way to manage spot market risk without the need to build generation. This enables entrants to compete with established incumbents and helps to drive competition and improvements in retail market structure.

A vibrant hedge market is also important for the industry as a whole. A transparent forward price curve represents the industry's best estimate of electricity future prices on the spot market. These prices provide an important signal to investors and help improve investment decisions. This is critical because the industry invests such large amounts in transmission and generation. Having the best possible information for these investment decisions can make a huge difference to the long-term efficiency of the industry.

We expect trade in ASX hedges to continue to increase in 2014, because in December 2013, the ASX launched three new hedge products: monthly hedges, options on quarterly hedges and quarterly peak-load hedges. This greater variety of products will help the market expand and gives retail entrants more choices to manage their spot market risk.

In June, financial transmission rights (FTRs) were introduced between Benmore in the South Island and Otahuhu in the North Island. FTRs are a special type of hedge product designed to manage spot price risks arising from transmission. FTRs protect against the risk that prices vary in different locations. This matters if the generator and retailer are the same entity and they are buying energy in a location with a high price and selling it in a location with a low price. In the past, this risk may have driven vertically integrated generator/retailers to compete only for retail customers that are close to locations where they have generation, possibly reducing retail competition. FTRs should improve retail competition by reducing the locational risk to generator/retailers. FTRs should also improve competition in the over-the-counter hedge market.

Dramatic hydro changes

2013 was a year of dramatic swings in the volume of water stored in our hydro lakes. We went from abundant water in January into a drought where storage plummeted to nearly 30% below average. Storage remained below average for most of the winter, and then there was abundant water again late in the year.

Because hydro generation comprises well over half of the generating capacity in New Zealand, the swings in hydrology amount to dramatic swings in the volume of fuel available to generate electricity. Market arrangements must support these inevitable swings.

In 2013, the market performed exactly as expected when water is scarce. Wholesale prices rose and thermal generators stepped up production, allowing hydro generators to conserve water. This is similar to what occurred in the first six months of 2012, which had the worst inflows on record. So for two years in a row, the market has responded to a severe shortage of fuel and delivered a reliable supply of electricity.

Impacts on the wholesale market

Continuing flat demand for energy and the commissioning of two new geothermal plants had impacts on the wholesale market in 2013. Demand has been relatively flat since 2008 compared to the previous years when there was generally annual growth in demand. This is despite continued increases in the fundamental demand drivers of energy use – gross domestic product and population.

Two new geothermal plants were commissioned during 2013 – Mighty River Power's Ngatamariki plant and Contact Energy's Te Mihi plant.

There were two significant announcements of reduced thermal generation in 2013, both of which cited flat demand and increased geothermal generation as causes. Genesis mothballed a Huntly coal-fired unit a year earlier than anticipated. At the same time, it announced that the previously mothballed coal-fired unit would be fully decommissioned. Contact announced it was likely to reduce the use of its gas-fired combined-cycle plant at Stratford and thereby delay the need for maintenance.

Different generator types work together

In this review we have looked at how different generator types work together, particularly when intermittent generation such as wind and hydro are unable to supply energy. Wind generation is intermittent either when there is too much or not enough wind, while hydro generation can be intermittent over longer timeframes when low inflows cause water to be scarce. Hydro and thermal generation are highly correlated with demand, reflecting the discretion these power station operators have to store fuel and use it when it is most valuable. On the other hand, wind generation is no more likely to generate during times of peak demand than at times of low demand.

Thermal is most negatively correlated with wind, which means that thermal plays the most important role firming wind generation. This is true whether half-hourly or daily data is used. The data shows that hydro generation is uncorrelated with wind generation, indicating it plays no role firming wind.

In 2012, we started using simulation models to assess how often individual generators were in a position to influence prices on the wholesale market. We have updated this analysis in 2013 and added an additional approach. Both measures suggest that generators are becoming less able to influence prices – a sign of increasing competition consistent with the low and falling market concentration seen in the wholesale market.

Events and enquiries

Perhaps the most significant event in 2013 was the automatic under-frequency load shedding (AUFLS) in November that caused widespread power cuts in the North Island. AUFLS is the last resort that the power system has to protect itself, so any time it is used, it warrants close attention. In this instance, testing of the link between the North and South Islands caused the AUFLS event. At the time of writing, we are still making enquiries and expect to publish a full report on this incident in 2014.

Enquiries completed in 2013 investigated commissioning of new plant and how the costs might be shared by participants, high prices during the drought early in the year, and a high spring washer price situation in June. The enquiries are summarised in this report, and the full enquiries are available on our website.

Energy demand remained subdued

Energy demand in 2013 was subdued, continuing the flat demand trend we have seen since 2007. This section describes the overall demand in New Zealand in 2013, the trends in recent years and attempts to explain these trends.

Figure 1 shows energy supplied by year since 2004. Prior to 2007 annual growth was the norm. 2013 saw slightly less energy supplied than 2012. The usual drivers of energy use – population and gross domestic product – continued to rise, so other factors are affecting demand. These could include demographic, economic and technological factors.

A possible source of reduced demand growth is the effect of the global financial crisis on manufacturing in New Zealand. Statistics New Zealand data shows that manufacturing output (excluding meat and dairy) fell precipitously during late 2008 and early 2009 but has remained fairly constant since then. As manufacturing tends to be energy intensive, this could account for some of the recent trend.

Figure 1 Total energy supplied

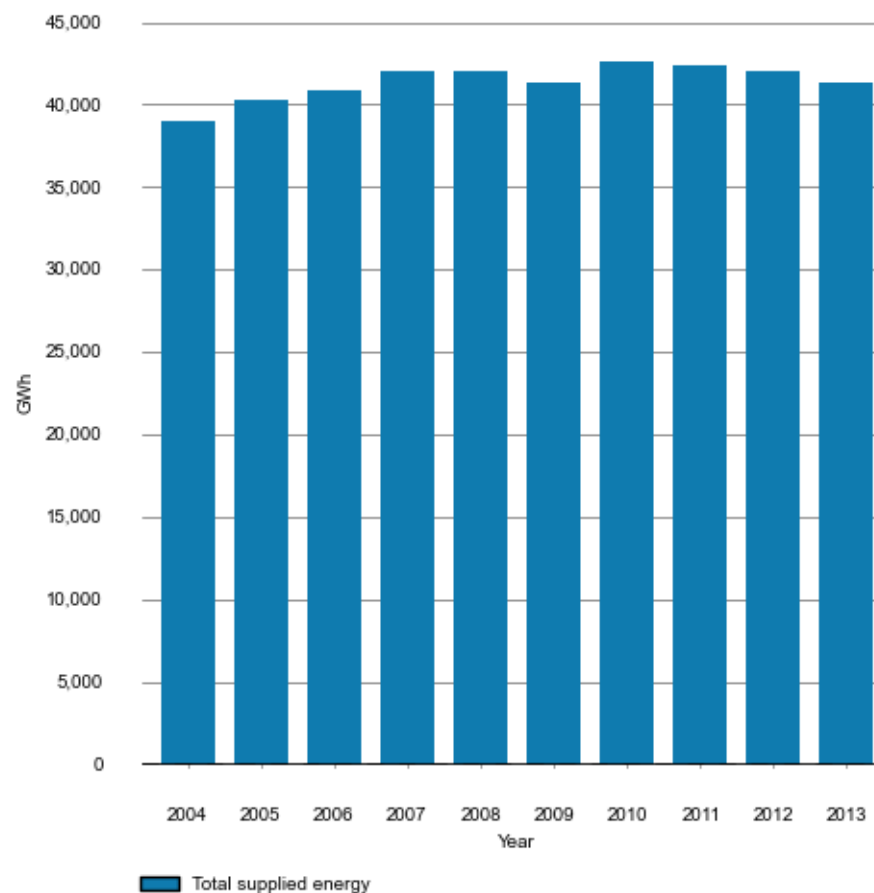


Figure 2 compares the monthly energy supplied in 2013 with the mean monthly energy supplied between 2008 and 2012. We have used mean energy supplied from 2008–2012 as a comparator for 2013 so we can compare 2013 with the period of flat demand that New Zealand has experienced. Figure 2 excludes demand from Tiwai because it is about 14% of national demand, and small changes at Tiwai can have a dramatic impact on national demand – see Figure 3.

The mild winter contributed to the subdued demand – NIWA monthly climate summaries state that July 2013 was the fourth warmest on record and August 2013 was the warmest on record. May and September saw above-average temperatures in most areas.

Figure 2 2013 monthly energy supplied compared with 2008–2012

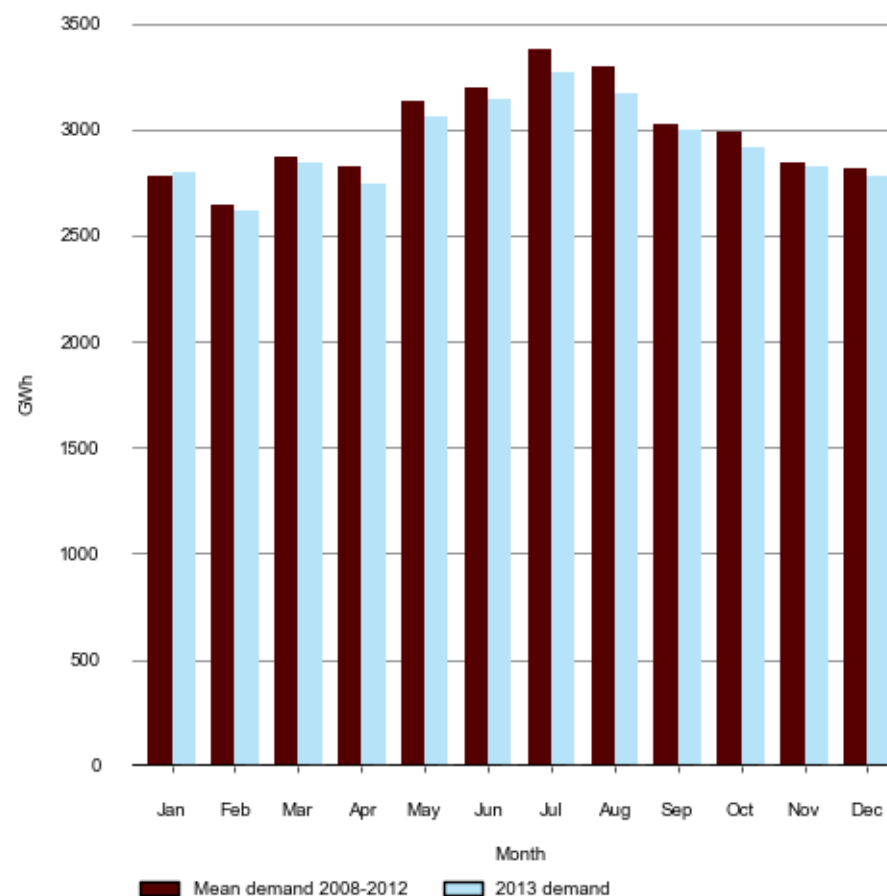
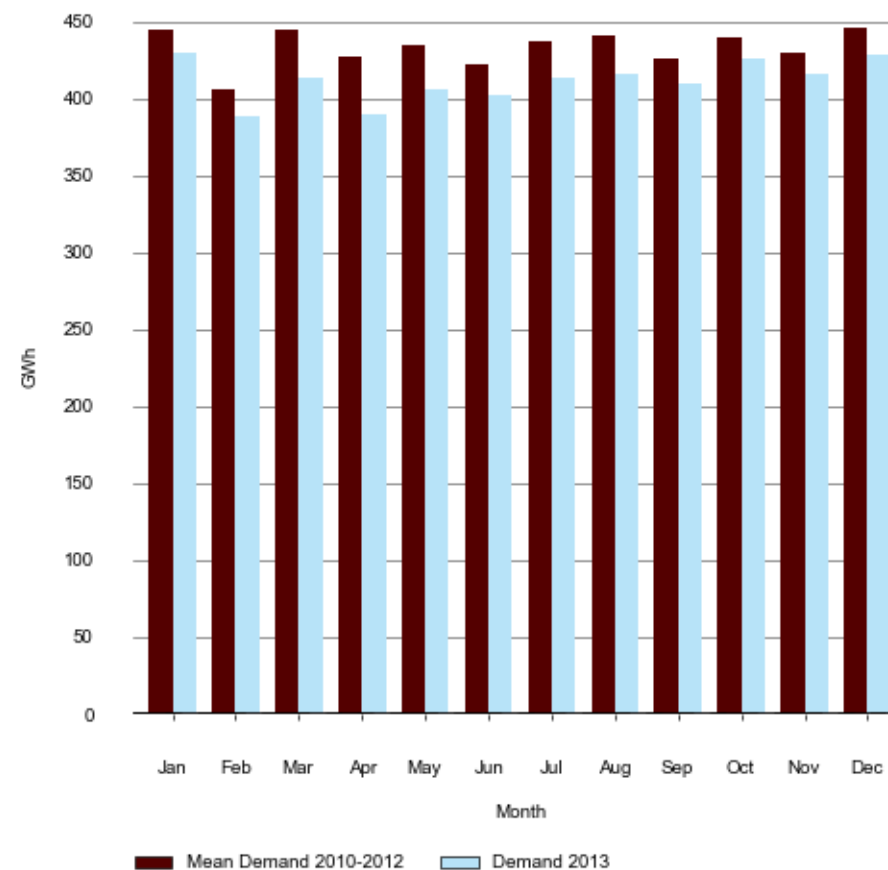


Figure 3 shows monthly demand at Tiwai compared with 2010–2012. We use 2010–2012 as a comparator because 2008 demand at Tiwai was affected by the dry year and 2009 was affected by a transformer fire. The chart shows a reduction in demand at Tiwai, but this is not large enough to account for the overall fall in demand in 2013 shown in Figure 2.

Tiwai has been in the news throughout the year as New Zealand Aluminium Smelters (NZAS) was renegotiating its energy supply agreement with Meridian. The revised agreement gives NZAS the option to reduce its contracted volumes from 572MW to 400MW as early as 2015, but this reduction must happen by 2017 or the rates revert to the 2007 contracted rates. NZAS can terminate the agreement from January 2017 provided it gives 15 months' notice. After 2017, NZAS can terminate the agreement with 12 months' notice.

Figure 3 Tiwai demand in 2013 compared with 2010–2012



Retail market becomes more competitive

2013 was a good year in the retail market. Competitive activity was high with special deals, entry, innovation, switching and a significant trade sale. We looked at developments in the retail market in 2013 and then examined the numbers of consumers switching retailers. The Authority uses a structure, conduct and performance framework to organise how we look at the various markets. We examined the structure of the market initially using indicators of market concentration. Next, we looked at 'saves' – a type of retailer conduct. Finally, we looked at changes in the costs of supplying energy and compared these to price changes.

Retail market developments

In reviewing the retail market performance, we questioned whether it delivers prices that are close to costs. Currently, there is no reliable measure of overall retail price in New Zealand. Prices must be modelled using published standard plans and average consumption. This approach cannot capture most of the competitive activity we know is occurring in the retail market through door-to-door sales and other special deals.

In 2013, various retailers offered cash-back discounts during the winter months for new customers. Meridian offered \$150 cash back over three months for new residential customers. In May, Genesis offered \$20 back per month for three months and \$30 back for three months for dual fuel customers. Contact offered \$80 and \$100 for electricity and dual fuel respectively for new student customers. Other offers included a two-year fixed-price deal from Mercury.

An aspect of the retail market that we do not measure, yet we know exists, is the discounts offered by door-to-door agents. Anecdotal evidence is that some of the best deals in the marketplace are available through this channel.

Innovative retail activity increasing

There were many good examples of new ideas and innovation in the retail market in 2013, such as offers of discounts, donations and the use of buying power. While electricity is a commodity, these retailers are differentiating their service even if they supply the same product.

Payless Energy launched in July in Dunedin with simple plans and an internet-based customer interface. It gradually built up customers throughout the second half of the year. Payless donates \$50 to a local charity for each new customer. Tiny Mighty donates \$50 to a nominated school for each new customer and a further \$10 for each year the customer stays with the company.

In September, Pulse announced a partnership with Grey Power that provides a group discount for Grey Power's 50,000 members. The partnership includes an agreement to not increase prices for five years and to reduce prices if wholesale prices fall. In essence, this innovation is an organised group of consumers using its buying power to get a deal in the retail market through an intermediary. Grey Power was in discussion with three retailers, indicating that a competitive retail market is a precondition for this type of arrangement.

The health of the market is also visible through the number of enquiries the Authority receives from potential retailers. These have increased recently, with enquiries from nine potential new entrant retailers in the last three months of 2013.

As well as new entrants, existing entities continued the trend of launching new brands, such as Mercury's GLO-BUG. These brands tend to be aimed at market segments and the Authority will continue to review whether the use of brands to segment the market leads to more competition.

Intermediaries active in the retail market

This year we have seen intermediary arrangements in the retail market. These arrangements can reduce transaction costs by providing a focal point for supply and demand. Intermediaries are especially important when one or both sides of a market are dispersed enough to make it difficult or costly to organise bilateral trades. Trade Me is a good example of an intermediary where both the sellers and buyers are dispersed. Trade Me provides a platform to bring them together, reducing transaction costs.

An example in the electricity sector is the previous arrangement between Energy Direct and Meridian where a smaller retailer leveraged off the scale of a larger retailer to reduce its transaction costs.

Simply Energy also provides a range of services to a wide range of parties, including independent generators, large commercial and industrial consumers, lines companies and retailers. In regard to retailers, Simply Energy provides a service to manage regulatory and registry duties, lowering the retailers' costs.

Lower transaction costs mean lower barriers to entry, so these kinds of developments should lead to increased competition in the retail market.

Consumer switching remains strong

Consumer switching continued to be strong in 2013. Figure 4 shows total switches and residential switches since 2004. It was a record year for total switches, and a near record year for residential switching. Table 1 shows annual switching totals from 2004.

Figure 4 Residential switches

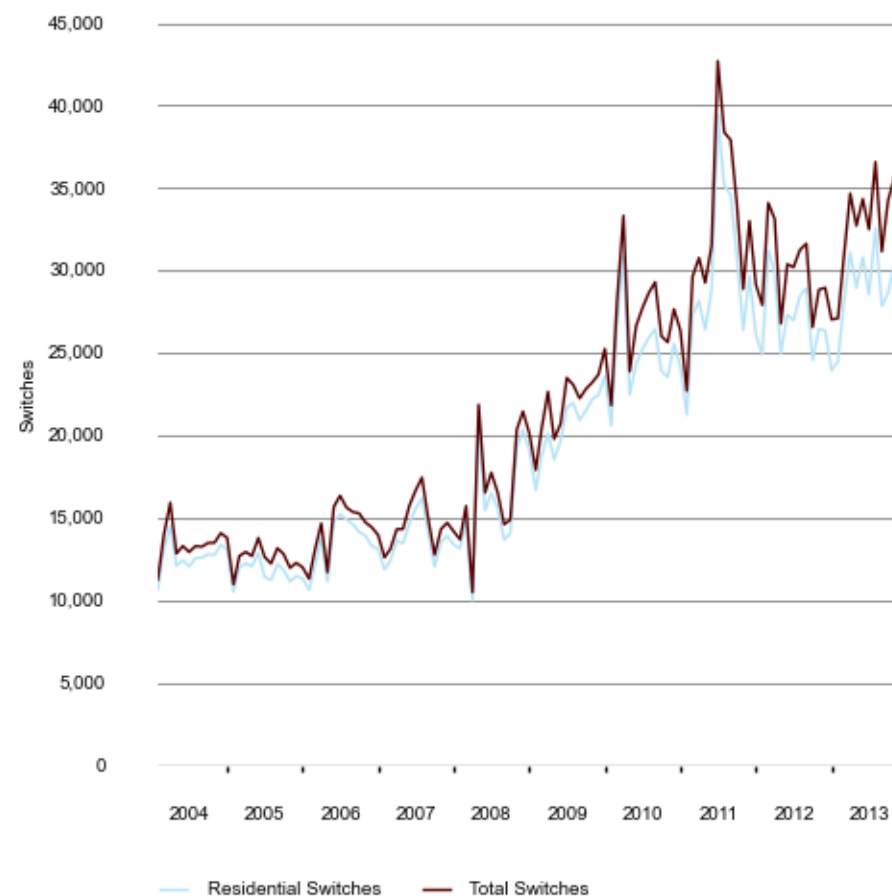


Table 1 Annual switching totals

Year	Residential switches	Total switches
2004	152,080	161,687
2005	140,404	150,248
2006	161,724	172,216
2007	164,785	175,154
2008	192,688	204,066
2009	248,144	265,254
2010	299,887	325,216
2011	354,189	387,952
2012	324,000	356,765
2013	350,299	396,871

Significant trade sale

In a workably competitive market, low barriers to entry act as a discipline for incumbents. Part of the calculation that a potential entrant needs to assess is the cost of exit. A low cost of exit means that fixed costs can be recovered. In May 2013, Trustpower purchased Energy Direct. While this is a reduction in competition in the short term, a trade sale is an important mechanism for exit, and this sale indicated that the mechanism is available to potential entrants. However, the alternative of entrants growing large enough to seriously threaten large incumbents is also very positive for competition.

Retail market structure: concentration falling

The Authority uses a structure, conduct and performance framework to assess competition in those parts of the electricity system that are organised into markets. Each indicator in isolation is limited, but in combination, these three indicators give a very good assessment.

Market structure is a useful indicator of competition because it is a necessary condition for competition. The Authority uses the Herfindahl-Hirschman Index (HHI) and the concentration ratio (CR) to assess trends in market structure. HHI is the sum of the squares of the percentage market shares in a particular market. It has an upper bound of 10,000 for a monopoly. CRX is the sum of the market shares for the largest X players.

Figure 5 shows the HHI and CR1–4 for the residential retail market for 2004–2013. These are ICP weighted average measures of regional markets by distribution company. These high-level measures of concentration show an on-going downward trend indicating that, overall, the market is becoming less concentrated.

Low concentration is a precondition for competition as competition is more likely when there are more suppliers fighting for customers.

While there is no absolute threshold for these measures where we could say that structure is 'competitive', we can see the trends are towards a more competitive structure. For comparison, the Commerce Commission has published the HHI for the 2011/12 financial year for fixed-line retail revenues (4,353) and mobile retail revenues for the telecommunication market (4,214).

Figure 5 HHI and CR1–4 for the residential retail market

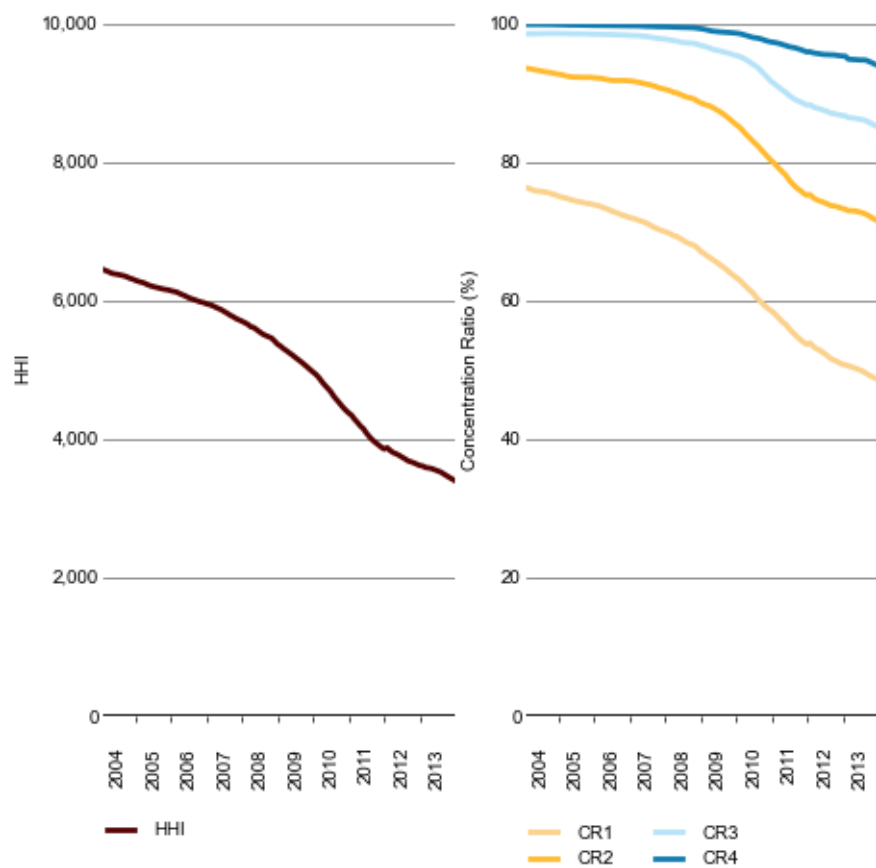
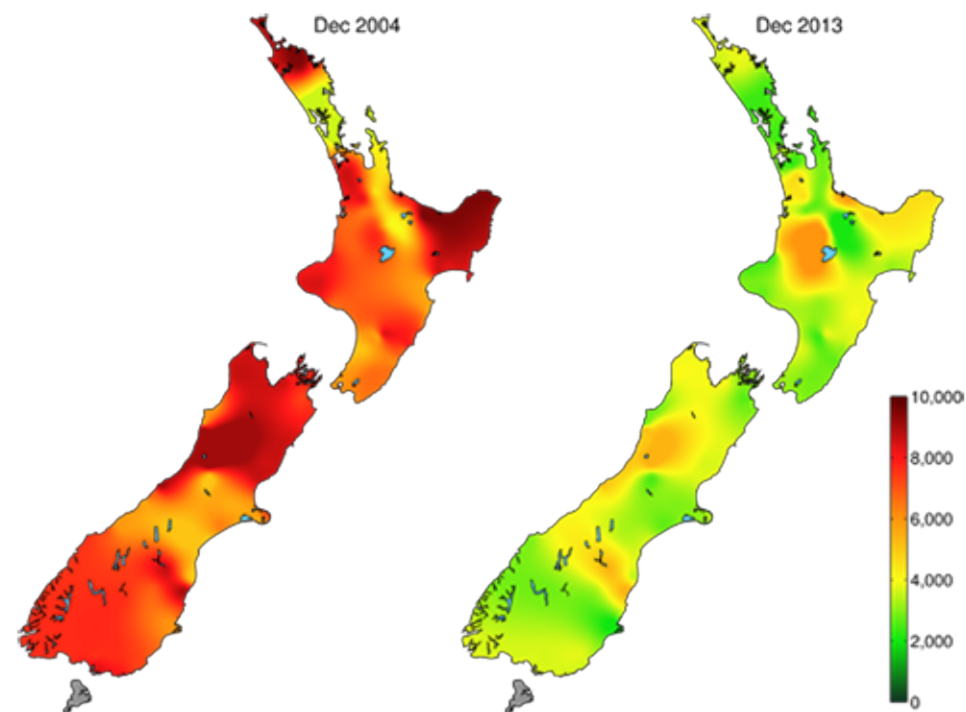


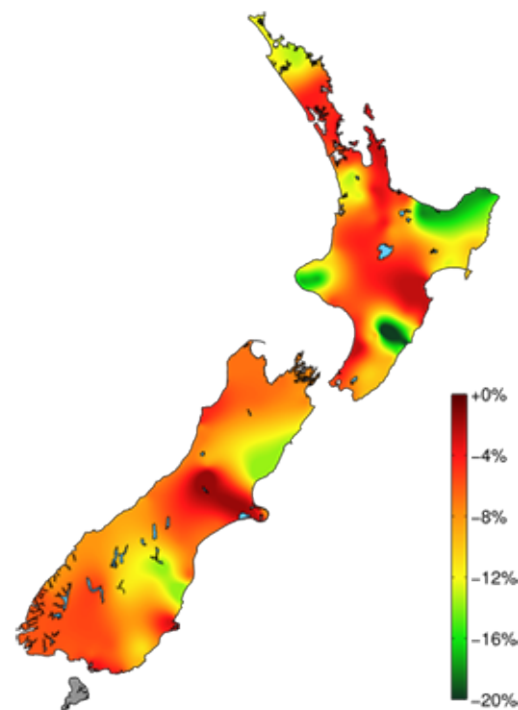
Figure 6 HHI in 2004 and 2013



Figures 6 and 7 show how changes in market structure are distributed around the country. The right-hand side of Figure 6 shows the current distribution of HHI for all market segments. The King Country, Waitaki, Tauranga and the West Coast of the South Island all have relatively concentrated markets. The main centres and Taranaki all have relatively dispersed markets. The change since 2004 is clear from the two maps in Figure 6.

Figure 7 shows the change in HHI in 2013 for all market segments. Taranaki, the eastern Bay of Plenty and the area around Dannevirke all show improving HHI. Canterbury, Hawke's Bay and Horowhenua had the least reduction in market structure.

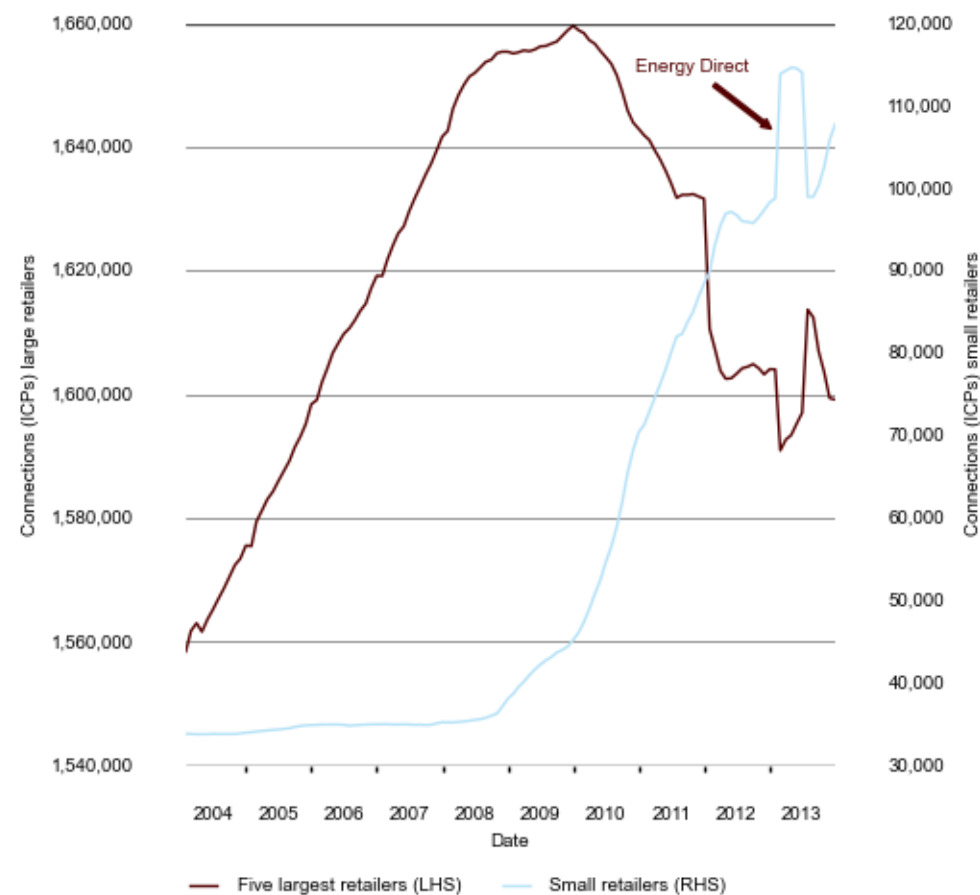
Figure 7 Change in HHI in 2013



Dramatic growth in small retailers

In 2013, there was dramatic growth in the market share of small retailers. Figure 8 shows the combined market shares for the five largest retailers and the combined market shares for the rest from 2004–2013 for the residential market. The chart shows clearly that small retailers started to grow rapidly during 2009, from about 35,000 customers to over 100,000 in 2013. While the axes are vastly different scales, the change is dramatic.

Figure 8 Large and small retailers



The blip in Figure 8 labelled ‘Energy Direct’ occurs because in March, Energy Direct began trading independently of Meridian, which until then had been managing Energy Direct’s registry commitments, so about 15,000 customers were recategorised from a large to a small retailer. In May, Energy Direct was sold to TrustPower, and those same customers were recategorised back to a large retailer.

Retail market conduct: price discrimination in the retail market

To complement the work on market structure, we also looked at conduct in the retail market. Competition policy and regulation has a well-developed list of anti-competitive conduct, which consists of variations on the theme of abuse of market power. Typical examples from the economics literature include restraints on trade, predatory pricing, price discrimination, non-price abuses of market power, foreclosure and other exclusionary practices.

Our analysis in electricity markets involves checking for anti-competitive conduct. For the retail market in 2013, we have looked at price discrimination in the context of switching, and the tendency for consumers who initiate a switch to be won back or ‘saved’ by the retailer they are switching from through a deal that is not generally available to other consumers.

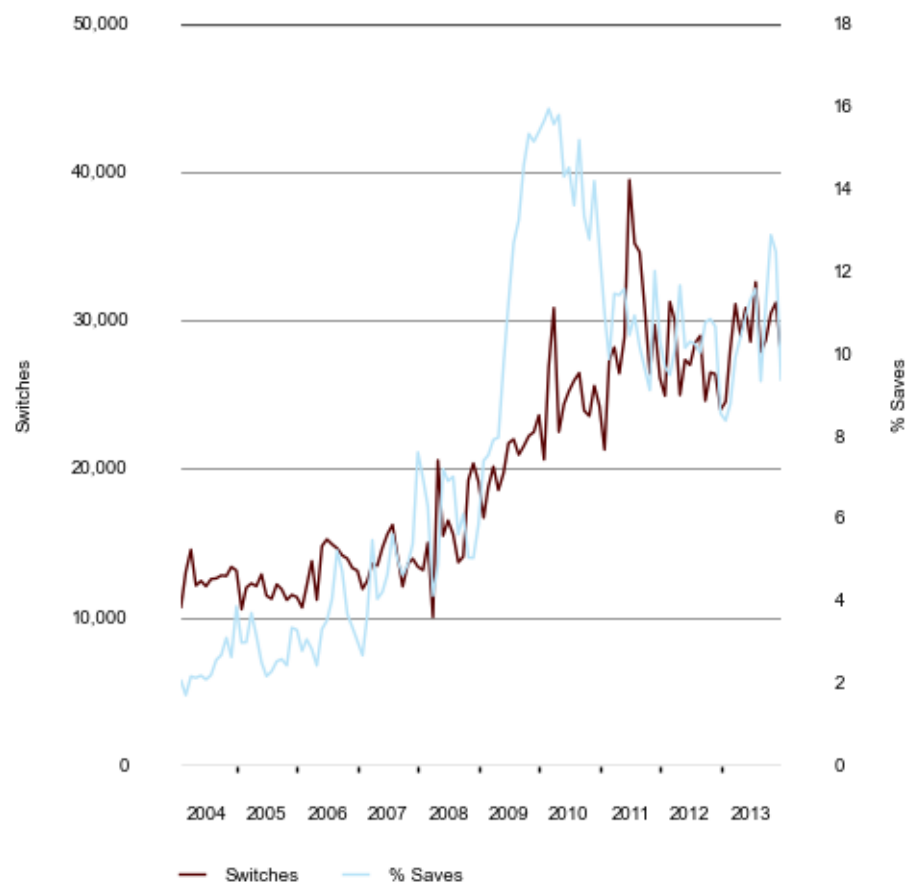
Switching saves

The 2013 switching data suggests an overall increase in the effort that retailers are putting into retaining customers through saves.

Figure 9 shows residential switching since 2004 as well as the percentage of initiated switches that are saved by the switched-from retailer. These are switches that are cancelled at the request of the customer so are assumed to be due to the switched-from retailer offering a better deal to entice the customer to cancel their switch decision. Saves are interesting from a competition perspective as a retailer presumably has to offer the customer a better deal to win them back, but this deal isn’t necessarily available to all customers. If the switched-to retailer is an entrant, the practice could reduce competition in the long term and alter the structure of the market. In turn, this may lead to consumers getting fewer offers in the future because of weaker competition.

Alternatively, saves could be seen as part of a healthy competitive market where firms fight for consumers. The Authority has initiated further work on this issue, which will determine whether or not this practice is anti-competitive and requires regulatory constraints.

Figure 9 Residential switches and saves



Saves as an example of price discrimination

'Saves' are an example of price discrimination – where different prices are offered to different market segments.

Price discrimination requires two conditions, and both are present in the retail electricity market:

- Retailers must be able to sort consumers in some way, either because they offer a set of deals and allow consumers to self-select or they are able to observe characteristics of customers in some way and map these to offers.
- Arbitrage – buying low and selling high – must be absent so that consumers cannot on-sell the goods for a profit and undermine the pricing strategy.

Segmenting the market

In the retail market, consumers tend to vary in their propensity to switch – some consumers will switch and some will not. We have observed these characteristics as part of the What's My Number campaign. In our national survey of consumers (available at www.ea.govt.nz), we found that a third of consumers (32%) report they are likely to shop around. The report says that certain market segments labelled 'bargain hunters', 'Gen Y' and 'battler mums' are most likely to switch. 'Affluent time-poor sceptics' and 'old, status quo' segments are unlikely to switch.

Having initiated a switch, a consumer has helped the retailer to segment the market between those who are willing to switch and those who aren't. With some cursory demographic data, retailers could further refine this segmentation.

Arbitrage

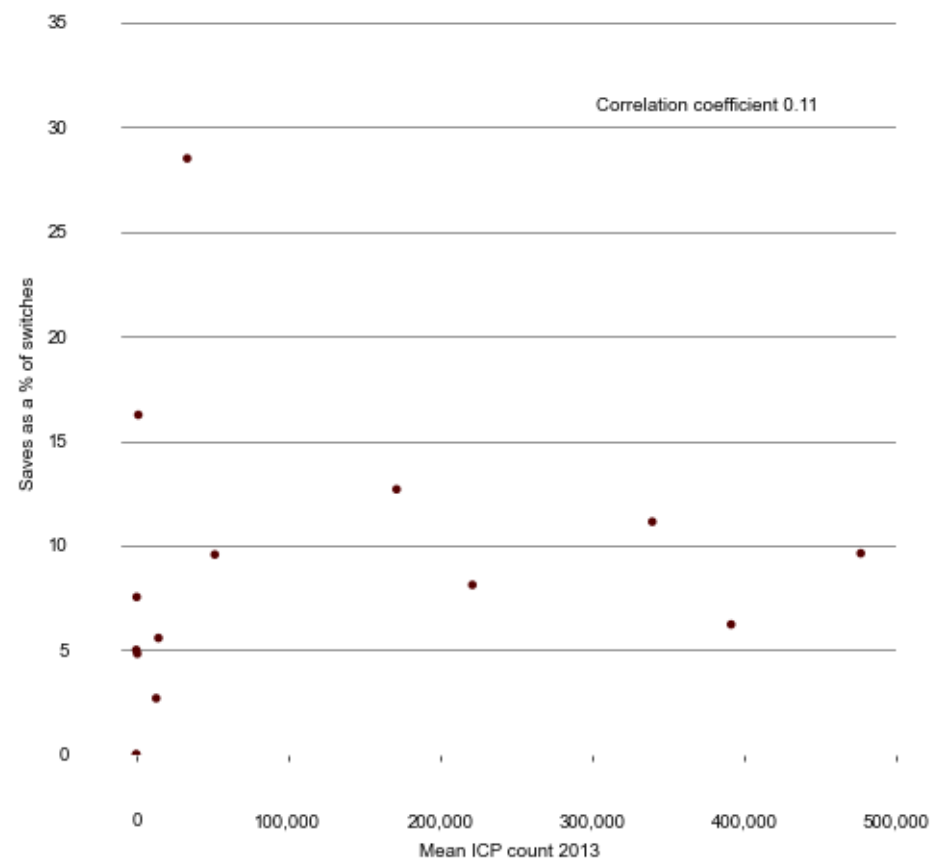
Arbitrage is not possible with electricity. Arbitrage in this market would occur if a consumer purchased electricity from a retailer and on-sold it to a second consumer for a profit. This would reduce the ability of the retailer to charge a higher price to the second consumer. Clearly, this is not possible to any great extent in retail electricity.

Price discrimination would be a problem if entrants lost a high percentage of customer acquisitions to incumbents. This would result in slower growth for the entrant and may reduce its ability to compete effectively.

Figure 10 shows the 2013 correlation between the size of the retailer and the percentage of saves. It is a scatter plot of the percentage of saves against mean ICP count for 2013 for the residential market. Figure 10 suggests that there is no relationship between retailer size and 'saves'. This is confirmed by the correlation coefficient, which is 0.11.

There is one obvious outlier in the data, which is small and has a very high loss rate for switches. If this outlier is excluded then the correlation coefficient is 0.35 indicating a weak positive relationship between the size of a retailer and the percentage of times it saved newly signed customers. Saves in this data and Figure 10 below are from the perspective of the switched-to retailer – switches where the retailer thought they had gained a customer but the customer was saved by the switched-from retailer and the switch didn't proceed.

Figure 10 Saves and ICP count



Another possibility is that the quality of customers won back is higher than those lost due to the switched-from retailer having better information on customers and only putting effort into winning back good customers. Entrants could end up with customers who are less desirable in some way, for example, those who are less likely to pay their bills or those who yield lower margins. If this occurred, entrants may be less likely in the long run to challenge incumbents, and this would be a concern. We are unable to observe this from our current information – to do so we would need some measure of quality of customers saved and lost to see if there was a significant difference.

Retail market performance: price analysis

We have completed two investigations on the relationship between price and cost. We asked the New Zealand Institute of Economic Research (NZIER) to create a cost index that uses the cost of components to estimate how costs are changing. We also modelled the cost to serve of different load profiles representing different market segments. This work shows how the costs of delivering retail energy to different market segments have changed over time.

Market performance revolves around how price relates to cost. However, we seldom observe the various components of cost. For example, capital costs of generation need to be modelled over time to calculate a figure for the long-run marginal cost. The cost of new-entry generation is not known to any great accuracy because it is very project specific, and individual retailers' costs to serve are not separately reported. Ultimately, performance is not currently measurable using market data. In the case of retail electricity, we don't often observe true price – we can't observe the number of door knockers in the market or the prices they are offering or the deals offered to save customers.

This means market data cannot be used to accurately calculate measures of conduct like the Lerner index, price cost margins and comparisons of changes in costs and prices. Any calculations like these need to be based on models of cost.

Similar to conduct, this analysis is aimed at discovering performance that is inconsistent with what we would expect from a workably competitive market. In the context of performance, we are looking for divergence between price and cost that can't be explained by fundamentals such as the cost to serve different load profiles.

Is the retail market workably competitive?

To find out whether the retail market is workably competitive, we need to look at how the costs incurred by electricity retailers compare to prices charged to consumers. NZIER developed an index for the retail cost for electricity. NZIER used the costs that a stand-alone retailer would incur by entering the market. This index shows how costs change over time, and we looked at this and also Ministry of Business, Innovation and Employment (MBIE) price data to see how these change over time. In a competitive market, the price of retail electricity should change as costs change.

For the period we looked at, the price data overestimates the price by excluding unadvertised discounts. Figure 11 shows that, for the period in question, residential retail prices are going up more slowly than costs. This is a strong signal of a workably competitive retail market, although this conclusion could be sensitive to our starting point.

The five cost components in the index are:

- energy cost
- transmission charges
- lines charges
- retail overheads and metering costs
- GST and the Electricity Authority levy.

These components are estimated for 151 offtake nodes and aggregated.¹ Note that the index is for all consumers, and we have not calculated it for different market segments.

Background to this data

The energy cost component is based on an estimate of the underlying annual average cost of hedged energy used to serve customers on fixed-price contracts of variable durations. This approach takes account of premiums paid by retailers to avoid the risk of very high spot market prices and market views about expected energy costs. It provides an estimate of energy costs to retailers who do not necessarily own generation assets. The energy price is estimated using the arithmetic average of the daily settlement price on futures contracts on the ASX for all trading periods up to 12 quarters ahead of the quarter to which the contract relates. The use of the ASX hedges means that this analysis only goes back to 2010.

Transmission costs are estimated based on Transpower's published pricing and methodologies. Estimated distribution charges are based on reported gross income for each distribution network divided by its volume supplied to customers.

Retail overheads include cost of capital, labour costs and operating expenditure. To estimate a competitive level of retail overheads, NZIER analysed major generator-retailers' annual reports.

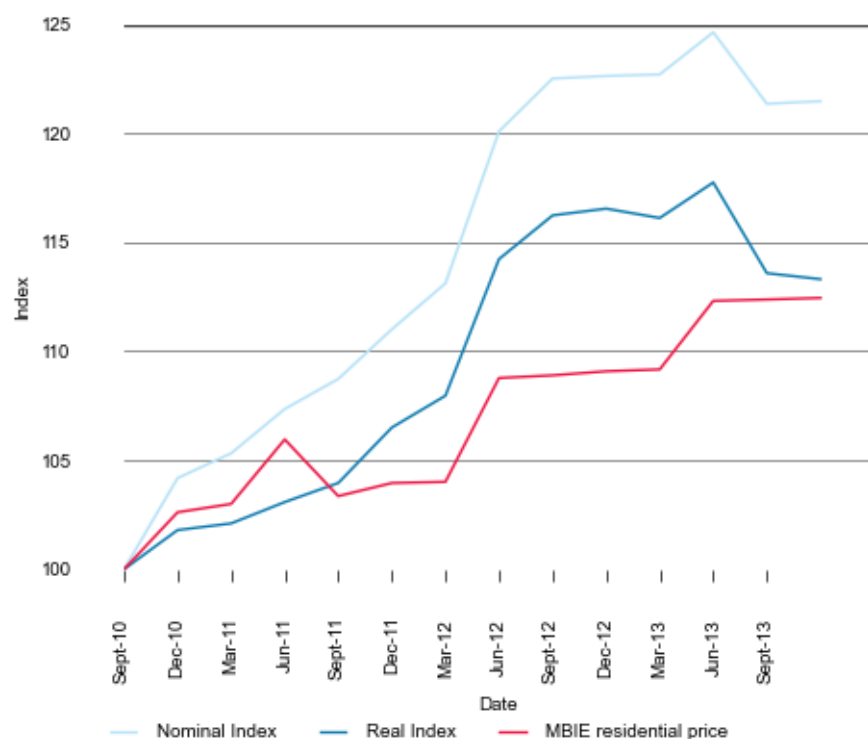
GST is applied on top of all other cost components. The results include the effects of the change from 12.5% GST to 15% in October 2010.

NZIER used the fact that the Electricity Authority levy is approximately 0.3% of retail bills to calculate the levy component of costs. There is a large one-off increase in the December 2010 quarter, which reflects the cost of establishing the Authority. MBIE's energy data tables show average retail prices (including GST) were 24.13c/kWh in calendar year 2009. This equates to a levy of 0.07c/kWh. NZIER has held this cost constant, consistent with the Electricity Authority's budget, which has remained about constant since it was created.

¹ These are the offtake nodes for which we have complete data series for all index components and exclude major direct connect nodes such as Tiwai and Glenbrook.

Figure 11 shows how the real and nominal cost index changes through time starting with a base of 100 for the September quarter 2010. It shows that costs have steadily increased since then apart from three quarters where costs have fallen.

Figure 11 Retail cost index

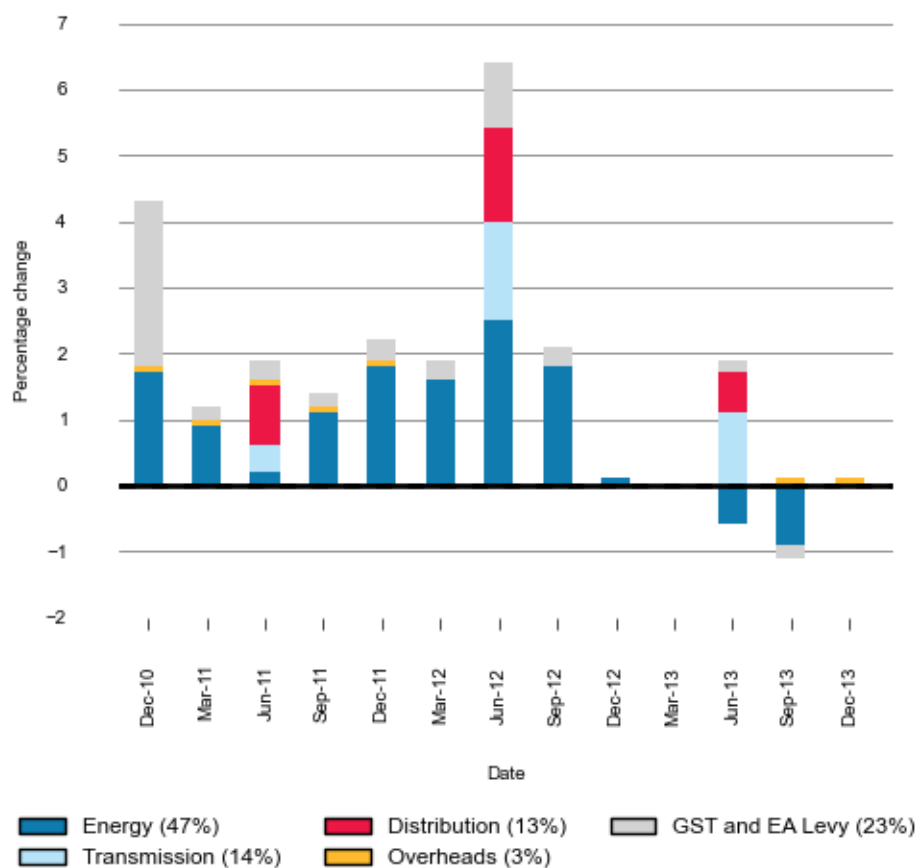


For contrast, we included in Figure 11 MBIE's quarterly survey of domestic energy prices (QSDEP) to show how this measure of price has changed over the same period. We treat this data with caution because it is based on standard published plans and average consumption and doesn't include the unpublished discounts available in the retail market such as those offered by door-to-door agents. For example, TrustPower stated in the media during November that only 5% of its customers were on the standard plan used by MBIE to estimate prices. Remaining customers were on less expensive plans. The Authority believes that the MBIE data overestimates the prices that consumers pay for energy because discounts are not taken into account.

We use the retail average (based on incumbent retailers), and we have also indexed this data at 100 for the September quarter in 2010. Note that the quarters are offset by a month, and we are charting an August quarter from the MBIE data with a September quarter for the NZIER index. Note also that the MBIE data is only for residential consumers, while the NZIER index is for all consumers. The cost to serve different groups of consumers varies as described later in this report.

The quarterly changes in the cost index are disaggregated in Figure 12, which shows that recent falls in the index are due mostly to a fall in the underlying energy price as measured by the ASX futures contract price. It also shows that increases in the cost of energy are the major contributor to increases in the index, with transmission and distribution contributing periodically. Of the total increase of just under 21.7% over the entire period covered by the index, 10% is due to a rise in energy price, 3.0% is due to transmission, just under 3% is due to distribution and GST accounts for 5.2%.

Figure 12 Changes to the cost index



Cost to serve different load profiles

In 2013, the Authority estimated the costs that different load profiles cause in the system, as we know different market segments pay different prices for energy. In a competitive market, different prices will reflect different costs. We looked at two examples of different load profiles then describe our modelling approach.

Figure 13 shows a box plot of Tiwai's consumption over 2013 by trading period. The rectangles on the box plot run from the lower to the upper quartile. The upper horizontal line is the lesser of either the maximum value in the data or 1.5 times the interquartile range (height of the rectangle) above the upper quartile. This is equivalent to about 2.7 standard deviations. The lower horizontal bar is the greater of either the minimum in the data or 1.5 times the interquartile range below the lower quartile. Outliers beyond the horizontal lines are shown as crosses. The red lines are the medians.

Figure 13 shows that Tiwai uses energy remarkably consistently through the day. Clearly, the smelter's processes require a steady supply of energy. Figure 3 (earlier in document) shows that production at Tiwai did vary throughout 2013, which accounts for the variation in the energy used within each trading period.

Figure 13 Demand at Tiwai by trading period

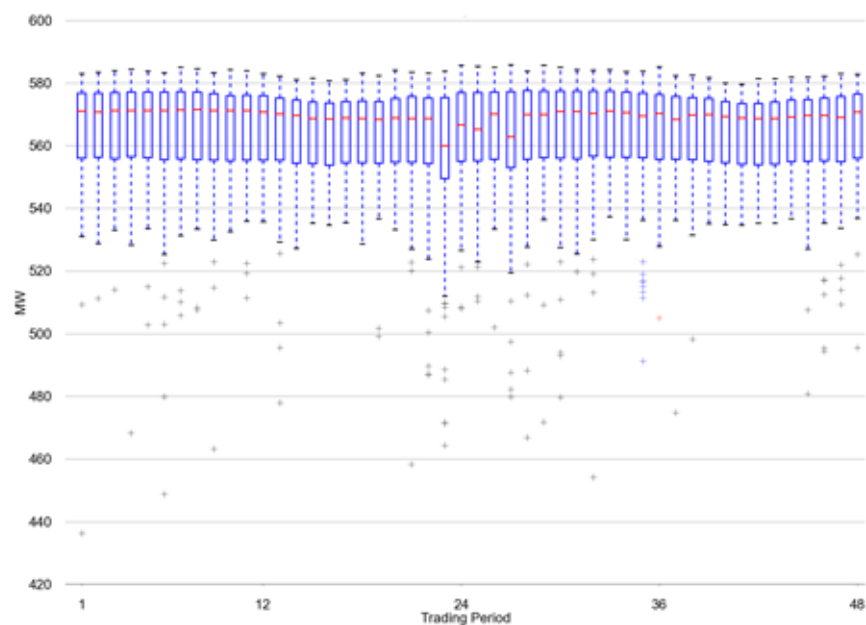
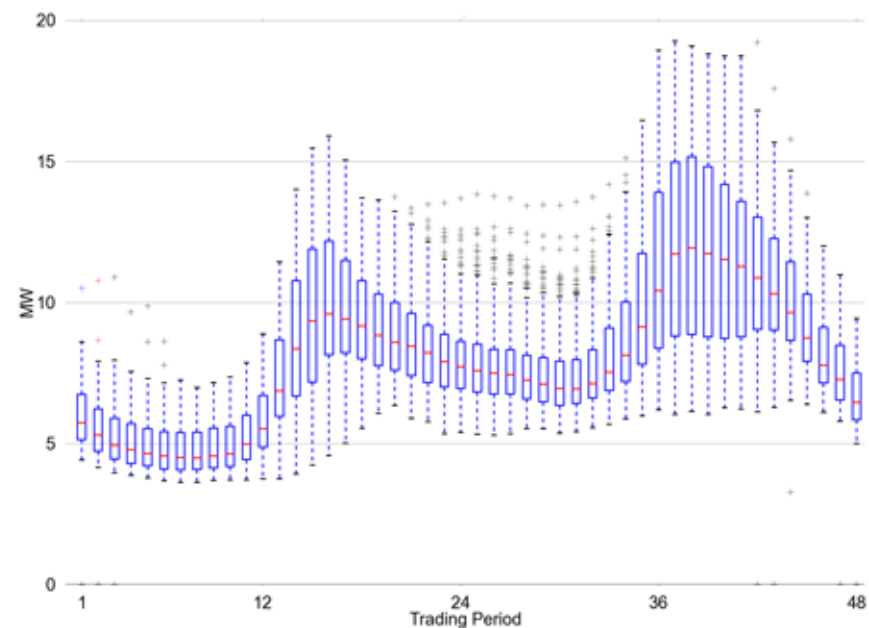


Figure 14 Demand at Pauatahanui – a residential GXP



In contrast with Tiwai, Figure 14 shows consumption at a typical residential grid exit point (PNI0331 at Pauatahanui). The maximum load is about three times the minimum, compared to the very flat demand profile at Tiwai. In addition, the upper and lower quartiles at Pauatahanui show a lot more volatility. These are obviously extreme examples as Tiwai requires steady energy as an input into its production process and residential demand is the most volatile load profile.

In 2013 the Authority used an optimisation model to estimate the least-cost generation and reserve requirements necessary to serve a given load profile.

The model simulates half-hourly demand from 1990. Year-on-year demand growth is based on historical demand levels, although demand growth in any given year has been forced to be positive to ensure that the model returns long-run marginal costs.

The starting point for the model's generation portfolio is the generating plant that existed prior to 1990. Because of the Clyde Dam's significant impact on available hydro capacity, the model also assumes that the dam was available from 1993 when it was completed.

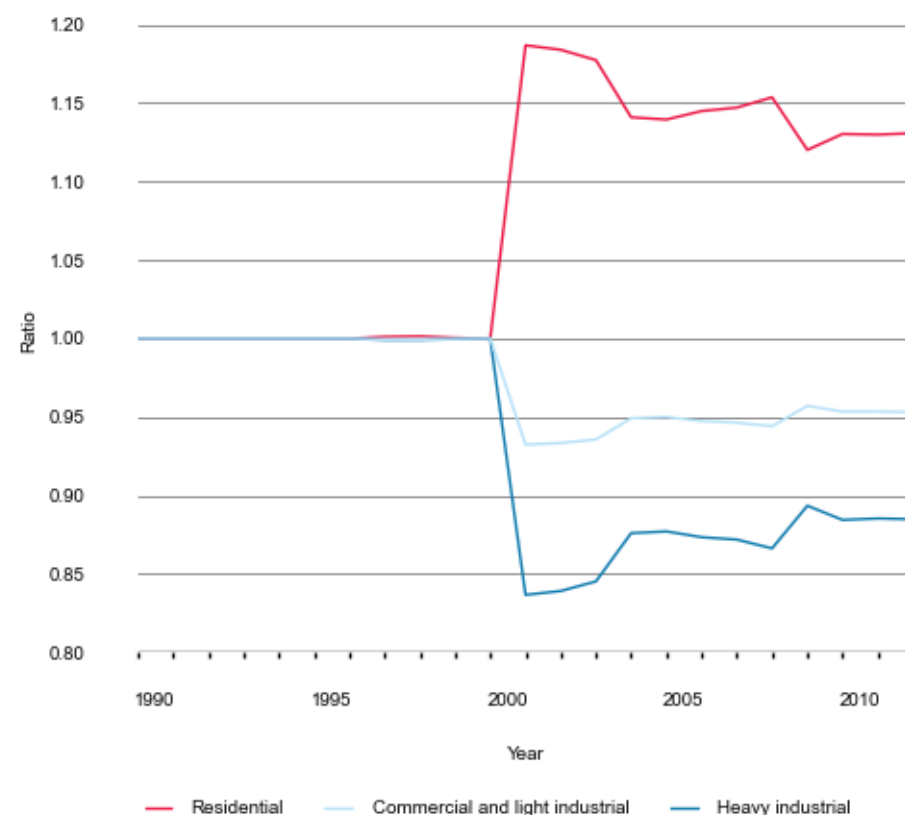
The model builds sufficient generation to meet total national demand based on the combined consumer demand profiles developed for each consumer type (scaled in each year to match total annual demand). The shadow prices derived by the model for each individual consumer demand profile represent the long-run marginal cost of supplying an additional consumer with a demand profile.

The results from the optimisation model are shown in Figure 15 which shows a cost index for three different demand profiles. The index produced by the model indicates that the cost differences were greatest in the early 2000s but have settled at lower levels more recently. The cost index for residential load in 2012 was 1.13 compared to 0.88 for industrial and 0.95 for commercial and light industrial.

Prior to 1998, there was little or no difference in costs between consumer types because of the excess hydro capacity available, which means the cost to supply an additional consumer was the same regardless of the shape of its demand profile because existing hydro generation could meet the extra demand.

After 1998, the cost of providing generation to deal with the peaks and troughs in residential demand (see figure 14 above) means that the relative cost of residential energy increased. The underlying driver is that residential consumption causes the winter and daily peaks shown in Figure 14, requiring more expensive generation.

Figure 15 Modelled index of cost to serve



Discussion of the analysis of price

The Authority did three retail cost and price analyses which paint an interesting picture of the retail market. The retail cost index shows that cost rises come from a variety of sources, with distribution and transmission causing some rise, but overall, it is the cost of hedged energy that is the largest contributor to costs. The increases in the energy cost are due either to the cost of generation or the cost associated with swapping a volatile income stream for a fixed one through a hedge contract.

The retail cost also suggests that costs have risen faster than prices during the period covered by the index – although the retail cost index is an estimate for all consumers and the price index is for residential consumers only.

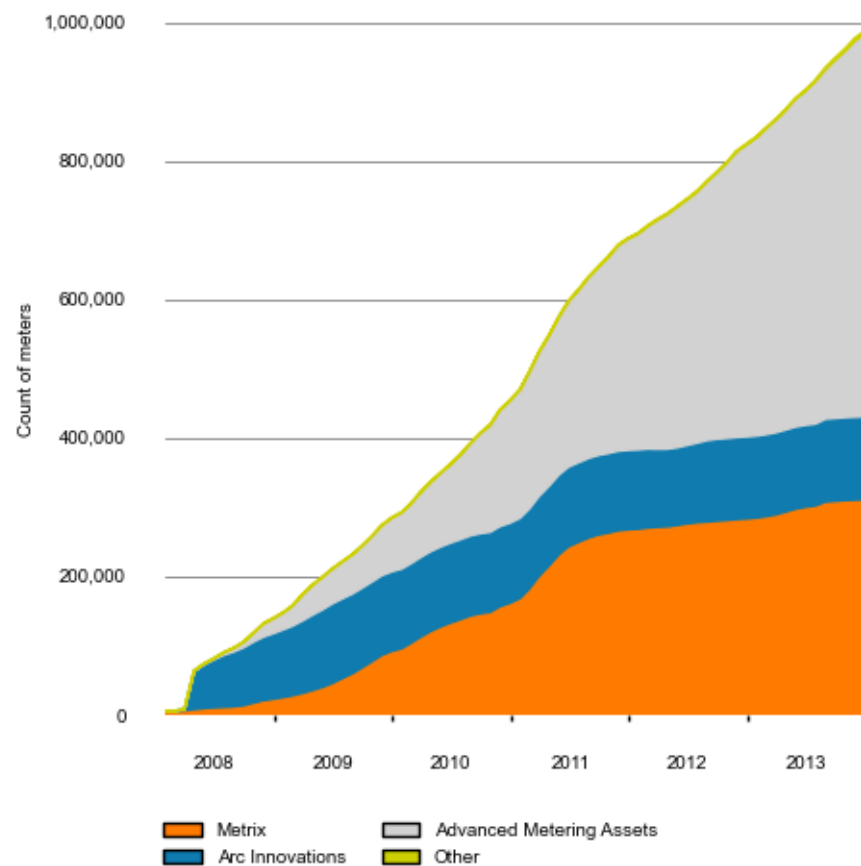
The cost of residential supply is higher than other market segments because of the load profile and the need to build transmission and generation to meet peaks. This being the case, if costs increase, the resulting price increases for residential supply should be amplified, but this doesn't seem to be the case over the time period that we have analysed. This could mean that costs take a longer time to filter through to prices, or it could indicate increased competition in the retail market.

The New Zealand metering market is undergoing a revolution. By April 2015, it is estimated that advanced metering infrastructure (AMI) meters or 'smart meters' will have been installed in the vast majority of installation connection points (ICPs). Smart meters are an important feature of the retail market as they have the potential to enable new services for customers, ranging from better information about consumption patterns to time-of-use metering.

Continued rapid growth of smart meters

Smart meters continue to be installed at a rapid rate, with about 100,000 added in 2013 to take the total to nearly 1 million. The smart meter market is dominated by three players as Figure 16 shows.

Figure 16 Market shares for smart meters



The current state of the metering market

Overall, it appears the AMI roll-out is positive for New Zealand's customers. Compared with many overseas jurisdictions, the implementation appears to be delivering genuine net benefits in a timely manner.

That said, the Authority is aware of concerns across a number of areas in the metering market raised by stakeholders, some of which may warrant closer scrutiny.

The transition to smart meters is rapid by international standards but also unique because it is entirely market-led, driven by a range of different retailers, network companies and meter owners within a context of metering being a contestable service.

What is emerging is a complex service model for metering in New Zealand, with a patchwork of different AMI implementations in different network areas – often with a mix of AMI providers scattered within a network area – and a series of interconnected contracts for services.

Three main meter equipment providers (MEPs) have emerged to date from this process – Advanced Metering Services Limited (AMS) (owned by Vector Limited), Metrix Limited (owned by Mighty River Power Limited), and Arc innovations Limited (owned by Meridian Energy Limited).

These MEPs can provide a raft of different services including meter reading, meter data management, remote disconnection/reconnection, load control, pre-pay functionality and smart-grid services to network companies.

There have been significant changes in who provides meter services. Some parties have decided to exit from being meter owners while others have decided to continue and/or expand, while others have decided to enter the market.

The contractual agreements that are emerging between the various different retailers and MEPs all appear to be unique. There appears to be a core service offering consisting of the provision of half-hourly meter data plus remote disconnection/reconnection. However, access to other functionality and services like load control, appears to be treated as bespoke add-ons. In addition, MEPs can provide other services to retailers, including acting as a 'one-stop shop' meter service provider in

terms of providing meter data management and interacting with all other MEPs on the retailer's behalf including, in some cases, manual meter reading services for customers with legacy meters.

Differential pricing of meter services

An area of potential concern is differential pricing for meter services, such that some retailers are being charged less than others. It appears that the basis for such differential pricing comes from two sources:

- Volume discounts – these could reflect the lower per unit cost to service a large number of meters for one retailer.
- First-mover benefits – a retailer securing a more favourable deal through being a foundation customer to help underpin an MEP's initial AMI roll-out and achieve a critical mass.

The Authority will look into this issue in 2014 to determine the extent of any volume discounts or first-mover benefits and whether these are large enough to have a material impact on retail competition outcomes.

Contracts acting to restrict competitive outcomes

A second concern raised by some stakeholders is that the contracts between MEPs and retailers are effectively locking in a particular technology path and cost and facilitating the emergence of a meter services market structure that will make it harder for new MEPs to enter the market.

The following aspects of the contracts are giving rise to such concerns:

- The requirement for the retailer to take services from an MEP if they win a customer with an AMI meter owned by that MEP. This requirement lasts for the duration of the contract, which typically is of the order of 15 years. While it is understood that most contracts have clauses allowing switch-out to another MEP if the original MEP cannot provide a service the retailer requires, a number of parties have suggested that the practical effect of such clauses is such that retailers are highly constrained in

their ability to switch out meters. As switching out a meter is an important countervailing power that a retailer has, this is a concern.

- Effectively granting the MEP the right to install an AMI meter if the retailer wins a customer with a legacy meter. Sometimes this right is specific to particular network areas, for example, a retailer may have granted the right to MEP A in the Vector network area and MEP B in the Unison network area.

The concern expressed is that retailers that have signed such contracts will be limited in their ability to switch to another MEP – potentially a new entrant – even if such an MEP offers a superior product or cheaper price.

We understand that four of the big five retailers have already signed such contracts with the main MEPs and that MEPs are requiring similar terms in their negotiations with smaller retailers.

While the Authority acknowledges that such contractual terms are likely to limit the ability of retailers to choose alternate MEPs to a certain extent, it notes the following:

- These contractual terms are likely to be a prerequisite for a market-led roll-out of AMI given the substantial capital investment involved. Thus, without the certainty offered to MEPs from these contracts, it is likely that the AMI roll-out and its associated benefits would not have occurred at all.
- Retail competition should act to place competitive pressure on existing MEPs. Thus, if a new-entrant retailer is able to secure metering services from a new-entrant MEP at greatly reduced prices or with superior technical capabilities, the retail competition success that such a retailer is likely to enjoy should result in the existing MEPs being forced to lower their prices or improve their technical offerings accordingly.

The Authority will continue to monitor both the metering market and the retail market to ensure that they remain contestable.

Addressing stakeholder concerns on metering

The Authority is currently looking at various metering matters to determine whether there are issues that need further attention.

Stakeholders were concerned that some AMI implementations lacked sufficient functionality, for example, home area network (HAN) chips, ripple relays, in-home displays and technology to support smart-grid benefits. While it appears that, in some cases, there have been missed opportunities, it is not clear that this is a significant problem in terms of lost value nor one that cannot be addressed through contractual means between a network company and an MEP in relation to smart-grid benefits. In addition, with developments such as the growing ubiquity of home internet, domestic wi-fi and smart phones, it is possible that many such investments would have turned out to be technological dead ends. As such, mandating particular technologies will almost certainly lead to worse outcomes.

Some parties have stated that retailers do not face strong incentives to offer smart tariffs and services to customers – although there are trials of these sorts of tariffs going on. The Authority is currently looking at such issues, including the design of network tariffs and the means by which retailers submit AMI metered data for reconciliation, to ensure that retailers and consumers face appropriate price signals.

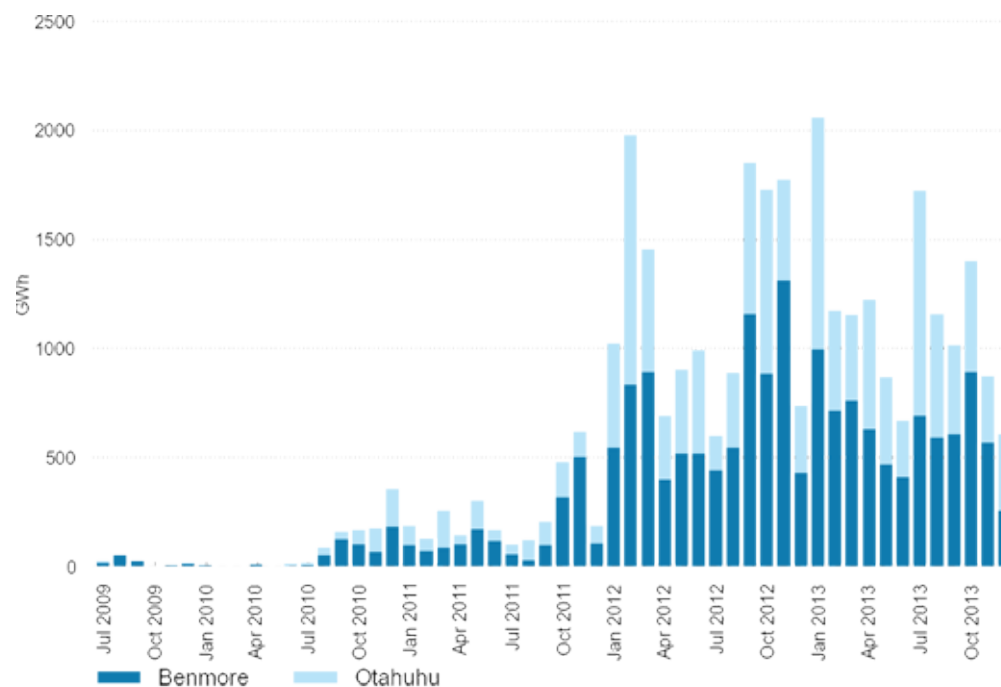
Some parties have suggested that unusual arrangements in some network areas are restricting the ability of retailers to choose the best MEP.

The hedge market made significant gains in 2013, the second consecutive year of strong growth. Record trading volumes, record uncovered open interest and the increasing use of exchange-traded hedges all contributed to these gains. The hedge market is an integral part of the wholesale energy market because it provides participants a transparent mechanism to manage spot price risk. This section looks first at the ASX market and then at other parts of the hedge market. New hedge products introduced in December are also explained.

ASX market gains

The 2012/13 summer drought saw record high volumes traded on the ASX in January 2013. This is likely due to participants seeking to cover their obligations in the face of rapidly falling hydro storage. Figure 17 shows over 2,000GWh traded in January for the first time ever. July was also a busy month on the ASX, with around 1,750GWh traded.

Figure 17 Trading volumes for ASX hedges



Uncovered open interest (UOI) hit record highs in the March, September and December quarters. Figure 18 shows UOI on the ASX climbing throughout the year. It peaked at over 3,600GWh.

Figure 18 UOI for ASX hedges

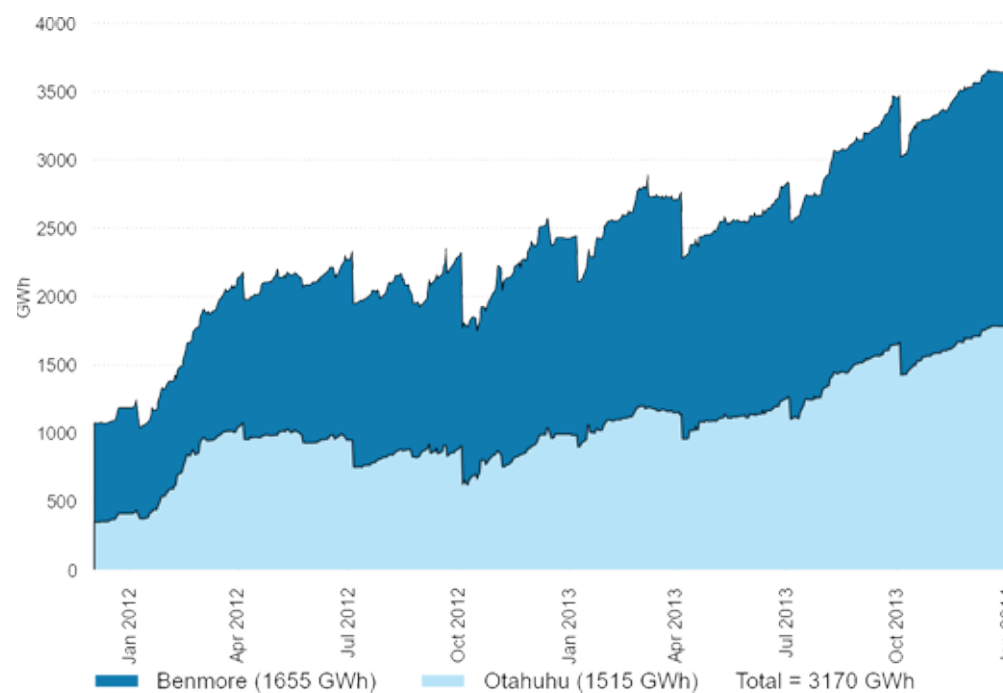
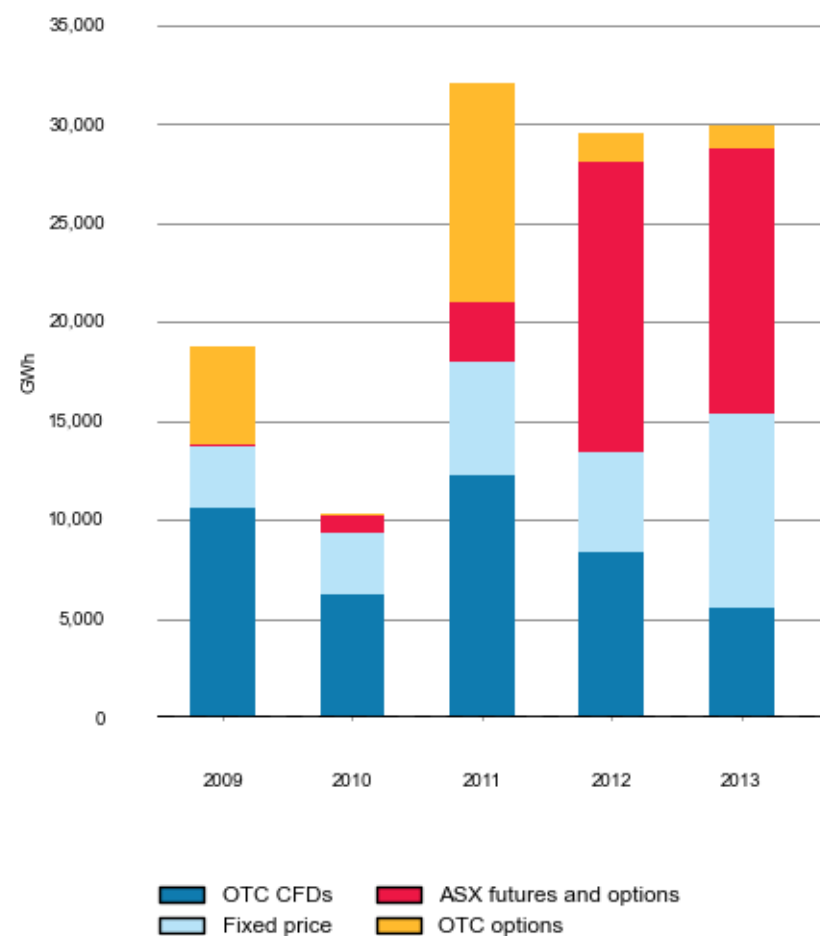


Figure 19 shows the different hedge products which participants use to cover their load and to get price certainty for generation. These bars show GWh traded in each year for each instrument. The chart shows a decline of over-the-counter options and contracts for difference (CFDs), and an increase in the use of fixed-price contracts during 2013 compared to the previous two years. ASX hedges have increased since 2011 and have the advantage of a transparent price and reasonable liquidity. Although ASX hedges are offered at only two nodes, the proposed extension of the FTR market should allow participants to construct cover at a larger number of nodes by combining hedges and FTRs.

Figure 19 The mix of hedge instruments traded



As usual, current quarter hedges were very volatile. Benmore hedges were trading at \$130 in April for June quarter hedges and just over \$30 in October for December quarter hedges. This hedge price volatility reflects spot price volatility, which, in turn, reflects supply and demand conditions in the market. For 2013, these were dominated by scarce water for hydro generation early in the year and abundant water late in the year.

Prices for 2014 ASX winter hedges peaked in April 2013 at just over \$100 for Benmore futures but spent most of the year just over \$90, falling to just over \$80 late in the year when water was abundant in the main hydro lakes. The successful commissioning of the HVDC Pole 3 may also have had an impact on winter prices at Benmore. ASX Otahuhu hedges spent most of the year trading \$5–10 lower than Benmore hedges. Longer-dated hedges didn't vary a lot from 2014 prices, but the market is a lot thinner.

A feature of the hedge market is the stability of the longer-dated hedge price. Its relative stability provides investors with an excellent estimate of the long-term spot price and therefore should help improve investment decisions. Figure 20 shows the average Benmore price for hedges that are less than one year from maturity and those that are between two and four years from maturity. The data includes 2012 and 2013 so covers two dry seasons indicated by peaks in the short-dated hedges.

The difference in volatility is obvious from Figure 20, with the prices of shorter-dated hedges affected by issues in the spot market. The longer-dated hedges are far less volatile. Part of the reason for this is that hydrology in one year tends not to affect the following year, so prices for longer-dated hedges are insulated from one of the most important factors affecting the spot price.

Figure 20 Prices for short and long-dated ASX hedges at Benmore

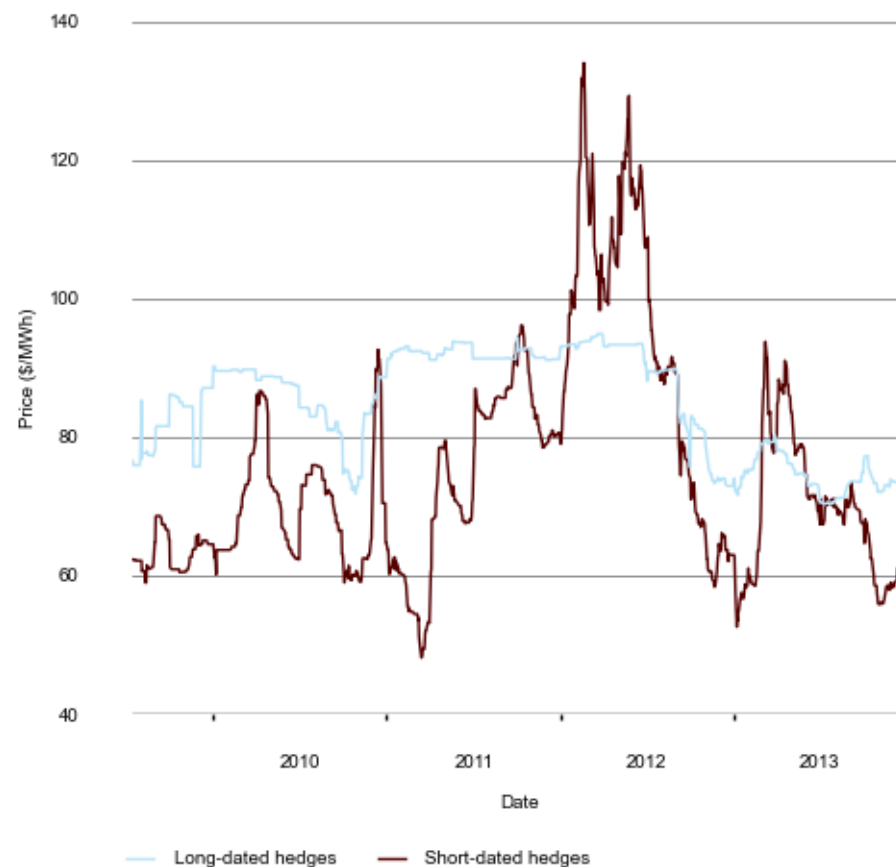
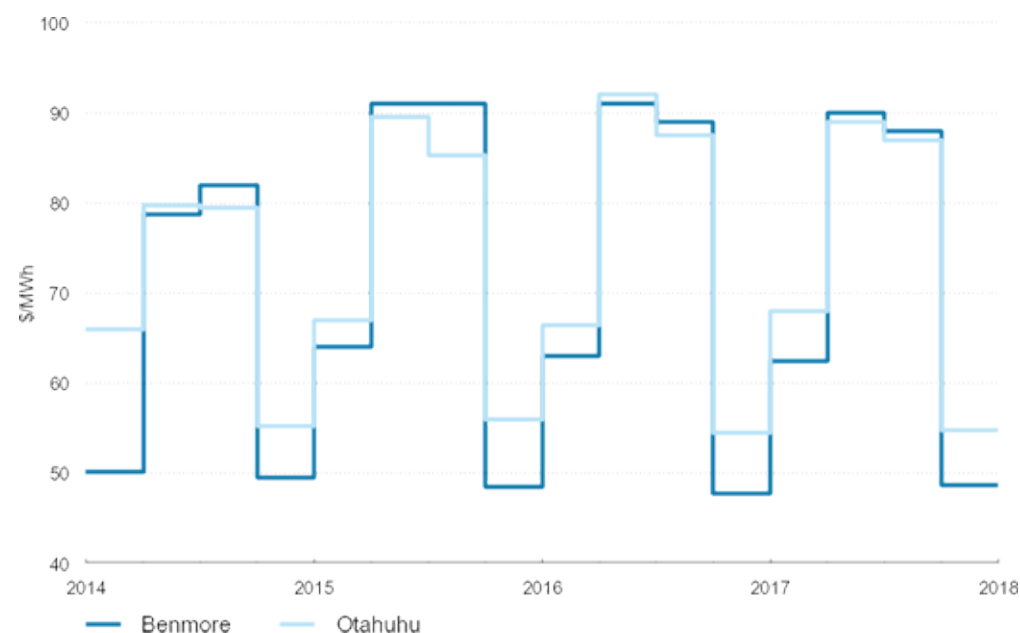


Figure 21 shows the forward price curves for ASX hedges at Benmore and Otahuhu from early October 2013. The very low prices for December 2013 quarter hedges – particularly at Benmore – are obvious and a result of abundant water in the South Island hydro lakes. Also apparent is that future year prices are independent of current year hydrology.

The forward price curve is an important part of the market mechanism because it provides a transparent indicator of the market's best estimate at long-run mean prices to investors and potential retail entrants.

Figure 21 Forward prices for ASX hedges at Benmore and Otahuhu



The bid-ask spread for ASX hedges for 2013 was around 3–4% throughout the year for most futures. The bid-ask spread is a measure of liquidity and the transaction cost of the trade because it helps reduce the risk of buying hedges. It does this simply by signalling that the loss to resell the hedge is small.

New hedge products for 2014

In December three new products were introduced on the ASX, thereby further increasing options for managing spot price risk. The first is an option over a 1MW quarterly futures contract at Benmore and Otahuhu. This is an option over the existing futures contracts offered on the ASX. The ASX will also offer a monthly futures contract, which is the monthly analogue to the existing quarterly futures contract. This is for 1MW and available at Benmore and Otahuhu.

The third product is a 1MW peak load quarterly futures contract available at Benmore and Otahuhu. This is a quarterly futures contract for energy for weekdays between 7.00am and 10.00pm. This product will allow parties with a high load profile during these hours to buy cover for just the hours for which they have this higher load. This is an important development because it is an exchange-traded product, meaning that it will provide price transparency for energy at this time as well as allowing consumers to buy futures cover to match their load profile.

Spot price risk disclosure

The four quarterly stress tests in 2013 continued to show that a variety of risk positions have been taken in the market. The stress test is just one of a suite of measures the Authority has adopted to manage dry years and other supply shortages. The stress test complements the customer compensation scheme that requires retailers to pay consumers during official conservation campaigns and scarcity pricing for temporary island-wide capacity shortages.

Our reporting continues to emphasise that we do not have a view on participants' risk positions, as long as these are knowingly being adopted. Our view is that the spot price risk disclosure statements clearly make these choices transparent.

Financial transmission rights launched

Interisland FTRs were introduced in 2013, with the first auction held in June. FTRs are a locational hedge, introduced to provide a mechanism for wholesale electricity market participants to manage locational price risk on the national transmission grid and thereby improve competition in the retail electricity market. FTRs are similar to CFDs between two nodes – in the case of the FTR market, these nodes are Benmore and Otahuhu. FTR contracts are directional and, in the New Zealand market, are available as obligations or options.

In contrast to standard hedge contracts, which are funded by the parties issuing them, FTRs are centrally funded from surplus money accruing in the wholesale electricity market – loss and constraint rentals. However, this means that an FTR is not guaranteed, however, and occasionally, because of extreme events, the price difference between Otahuhu and Benmore may not be fully covered by the FTR. As with all financial products, FTRs have risks attached to them, which traders need to understand.

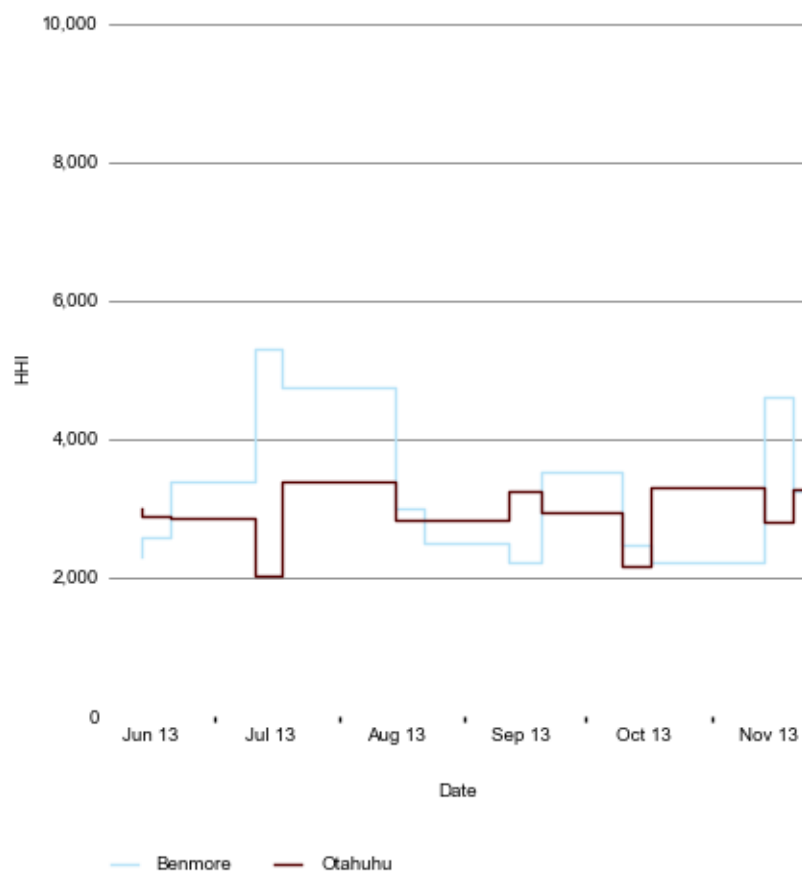
An obligation FTR includes both positive and negative price differences between the two nodes and, as such, effectively moves the FTR volume to the other node. An option FTR only includes the positive price differences between the two nodes, thereby covering against downside risk but not counteracting upside risk. Providing both of these products allows participants to purchase the locational hedge cover (or speculative exposure) that best suits their risk profile.

The FTR auction horizon is being progressively lengthened so that, by June 2014, FTRs will be available up to 24 months in the future.

The Authority is monitoring market shares of FTR options. So far, the auctions have traded \$10.5m worth of FTRs based on purchase price. Early trading has shown that the options are far more popular than the obligations. The total purchase cost for options since FTR trading began is \$10.4m while the total purchase cost for obligations is \$0.1m, about 1.2% of the option cost.

Figure 22 shows the HHI for all FTR options that have been auctioned to date. This data includes both primary and variation auctions but excludes secondary trades of which there have been very few to date. The blue line in Figure 22 is the BEN_OTA option FTR where the holder of the FTR is entitled to be paid the sum of the positive trading period price differences between OTA and BEN times the FTR quantity (in this case, OTA minus BEN).

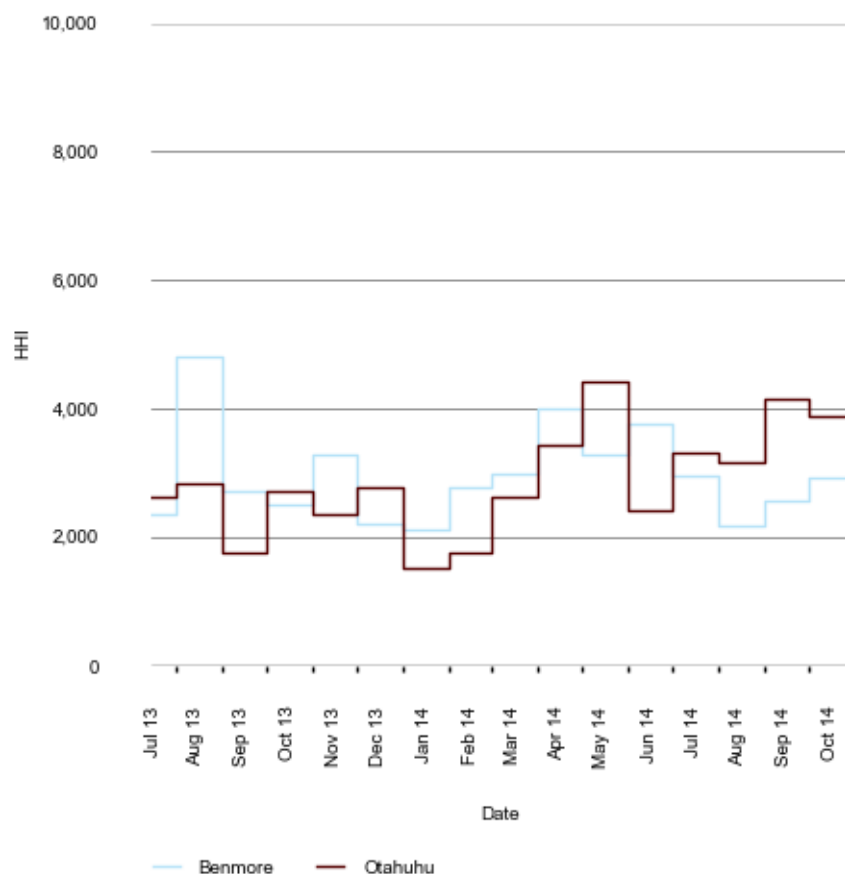
Figure 22 HHI for FTR auctions



Although it is early days, the chart shows that concentration is low in the option market in both directions. The HHI for different maturity dates is perhaps more important in the FTR market. This is because, in other jurisdictions, we have observed that participants with market power in the spot market can use this to increase the pay-off for FTRs. This is only profitable with a weighted position in the FTR market that exceeds the holder's need for FTRs due to their net position in the spot market. Any sign that a participant is building such a position for FTRs at a particular maturity date could be a precursor for exploiting market power in some way.

Figure 23 shows the HHI for FTR options based on their maturity dates. This chart includes all trades. Again, although it is early days, the FTR market looks to have low concentration.

Figure 23 HHI by maturity date



We can also construct a synthetic price for FTR obligations using ASX hedges. For example, we can construct a BEN_OTA obligation FTR by buying an Otahuhu futures contract and selling a Benmore futures contract. Conversely, we can construct an OTA_BEN obligation FTR by selling an Otahuhu futures contract and buying a Benmore futures contract. The difference in cost for each pair of trades is the synthetic obligation FTR price for the three months that the hedges cover in either direction.

We can compare the market prices for FTR obligations with this synthetic price to make an assessment of the value that the FTRs are adding. An example is presented below.

In early November, the bid price of a June quarter Otahuhu futures contract on the ASX was \$78.90. The offer price for a Benmore futures contract was \$83.50, so selling the Otahuhu contract and buying the Benmore contract for a total cost of \$4.60 would give the equivalent of a three-month OTA_BEN obligation FTR. While FTR obligations are not traded much now, we expect this to change in the future, so this measure should become more relevant.

■■■■ Developments in generation – responding to flat demand

The flat demand seen since 2008 has meant some existing generation is being decommissioned and some planned generation is being deferred.

We reviewed how hydro storage evolved throughout the year. We also looked at how generating capacity has evolved through time and analysed how these different generator types interact with each other, in particular, the importance of thermal plant for firming intermittent generation like hydro and wind. Wind generation is bid into the market at 1 cent, so we looked at how this affects prices.

Developments in generation for 2013 are set out next.

Hydrology in 2013

The year started with a summer drought that affected both Islands. Figure 24 shows national storage, mean storage and the hydro risk curves for 2013. This chart shows the dramatic shift that the hydro system went through early in the year from abundant water to scarce water. Figure 24 shows that storage went from just under 4,000GWh in January to 2,000GWh in May. Storage climbed back above average during July and never got close to the hydro risk curves despite the steep decline early in the year.

Figure 24 Mean storage, actual storage and the hydro risk curves

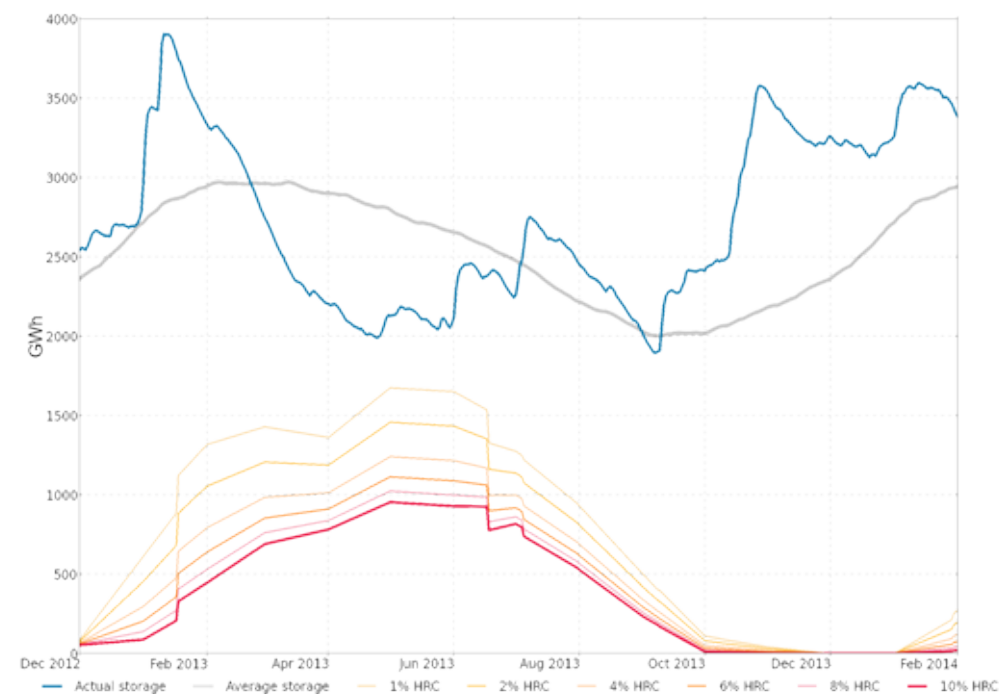


Figure 24 also shows abundant storage at the end of October at 77% above average. This resulted in low spot and hedge prices for most of the December quarter.

Generation capacity by fuel type since 1970

Generation capacity by fuel type has become increasingly diverse since 1970, as shown in Figure 25. The chart of generation capacity by fuel type since 1970 shows that fuel types have diversified since the early 1990s. Since 1992, there have been 63 stations built: eight biogas, two diesel, 14 gas, 10 geothermal, eight hydro, 18 wind and three wood waste. Figure 25 reveals this increasing diversity is attributable to changes in technology, limited opportunities for hydro, renewables policy and relative fuel prices. This also reflects the institutional arrangements governing investment, which do not constrain the choice of investment type or location but merely reward cost-effective investment.

Figure 25 Generation capacity by fuel type

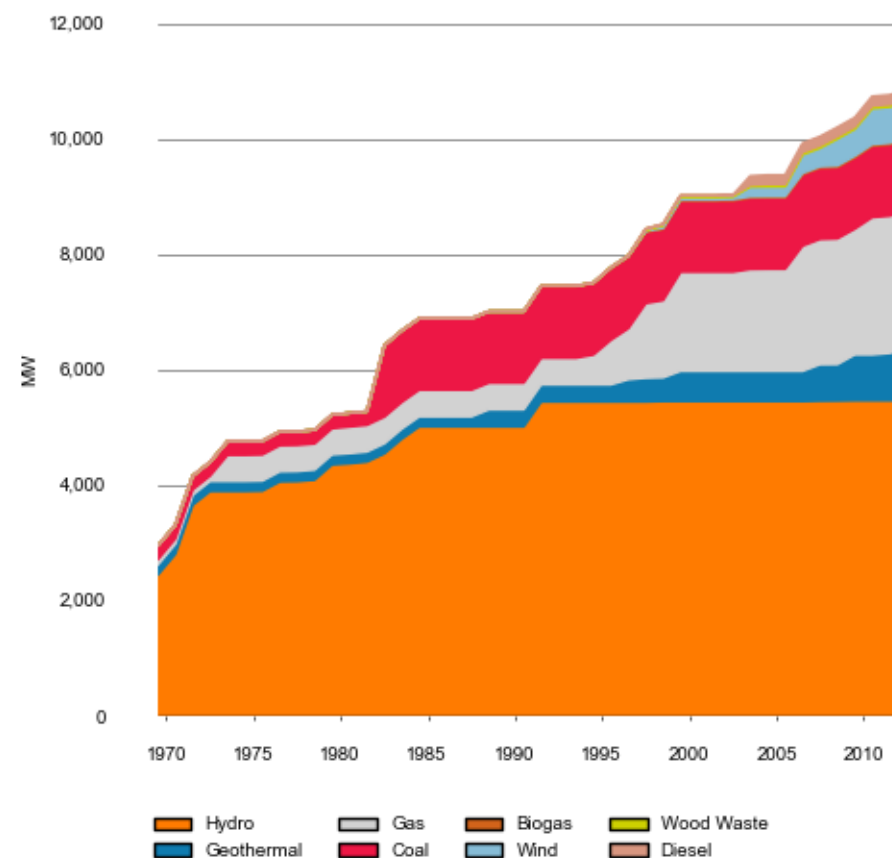


Table 2 shows mean plant size built by decade. The average station size climbed rapidly during the 1960s and 1970s as large South Island hydro schemes and the Huntly generators were built. The average plant size fell from the 1980s as new generation shifted towards wind, wood waste and smaller geothermal. Again, this reflects both a technology shift and the prevailing institutional arrangements.

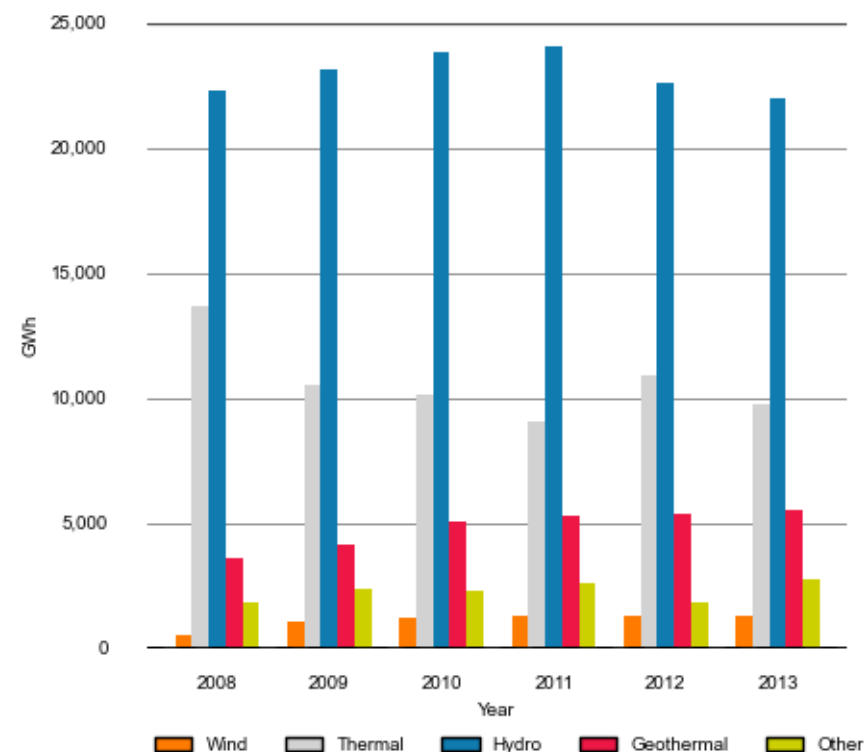
Table 2 Mean station size built by decade

Decade	Mean station size built MW
1960s	332
1970s	972
1980s	537
1990s	440
2000s	332
2010s	192

Generation by fuel type in 2013

In 2013 geothermal generation increased and wind was unchanged from 2012. These technologies are relatively small compared with thermal and hydro generation. Figure 26 shows generation by fuel source from 2008. It shows that in dry seasons (2008 and 2012) thermal generation became economic and substituted for hydro generation. The 'Other' category contains a mix of generation including cogeneration, diesel and small embedded generation that could be using any fuel type.

Figure 26 Annual generation by fuel type



Fuel type interaction

We have analysed how different types of generation work together using a correlation coefficient matrix for total generation, wind generation, thermal generation, hydro generation and hydro storage in Table 3. These correlations are calculated from daily data for 2008–2013.

Correlation coefficients measure how two series of data move together. A correlation coefficient of 1 means that two series move exactly together, so when one series rises, so does the other. Table 3 shows a series is perfectly correlated with itself where the diagonal entries are all 1. Two series with a positive correlation coefficient are said to be positively correlated.

In contrast, a coefficient of -1 means that the two series move perfectly opposite to each other, so when one rises, the other falls. Two series with a negative correlation coefficient are said to be negatively correlated.

Finally, a correlation coefficient of 0 means that two series move in an unrelated way, so movement up or down by one series is unrelated to movement of the other. Two such series are uncorrelated.

Table 3 Correlation matrix between different generator fuel types

	Total generation	Wind generation	Thermal generation	Hydro generation	Percentage mean storage
Total generation	1.00				
Wind generation	-0.03	1.00			
Thermal generation	0.52	-0.34	1.00		
Hydro generation	0.60	-0.04	-0.25	1.00	
Percentage mean storage	-0.13	0.21	-0.63	0.35	1.00

Table 3 and the following figures show relationships and interactions between fuel types.

We used total generation as a proxy for demand. A high positive correlation between a generation technology and total generation measures how useful that technology is at meeting demand.

Thermal and hydro generation are both highly positively correlated with total generation (0.52 and 0.60 respectively), reflecting the discretion the operators of those plants have because of the ability to store energy in the form of fuel or water storage.

The negative correlation between thermal and wind indicates the extent to which this intermittent technology requires thermal firming. This is likely to occur because thermal plant is the frequency-keeper or the next available generator when wind generation drops off or picks up. This same correlation between wind and thermal occurs when we use half-hourly data.

Figure 27 shows the relationship between thermal generation and hydro storage and gives a further indication about the role of thermal generation in New Zealand. Our small quantity of hydro storage means that we go through periods of acute fuel shortage – for example, the first half of 2012 and early 2013. During these times, thermal generation increased to ensure security of supply. Figure 27 shows a 60-day moving average of thermal generation and South Island hydro storage as a percentage of the mean storage. The dry seasons in 2012 and early 2013 are apparent in the chart, as is the strong negative correlation between hydro storage and thermal generation.

Figure 27 Thermal generation and storage 2012–2013

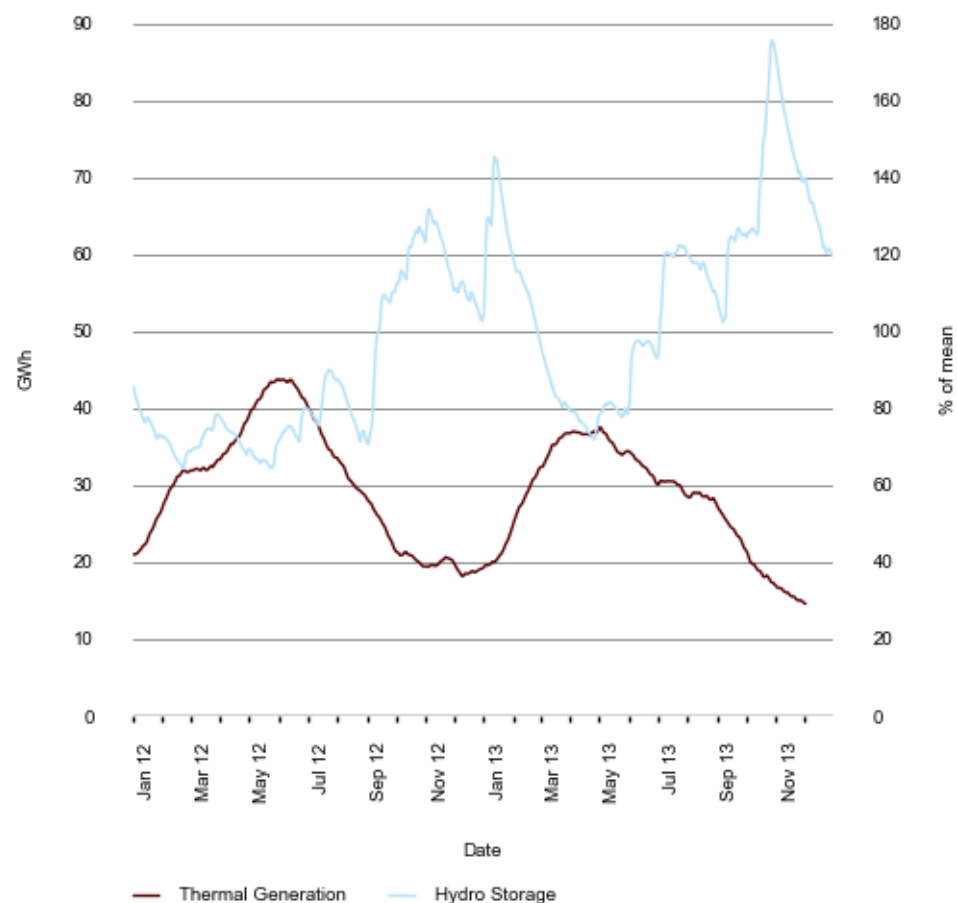


Figure 28 shows daily wind generation and a 60-day moving average line. Wind generation tends to be volatile as the daily series shows, but the moving average is also interesting as it shows relatively long-term volatility. Because wind is bid into the market at 1 cent per MWh, wind generation is a proxy for how windy it is. The chart suggests shows that there are windy 'seasons' and not so windy seasons.

Figure 28 Daily Wind generation and with a 60-day moving average

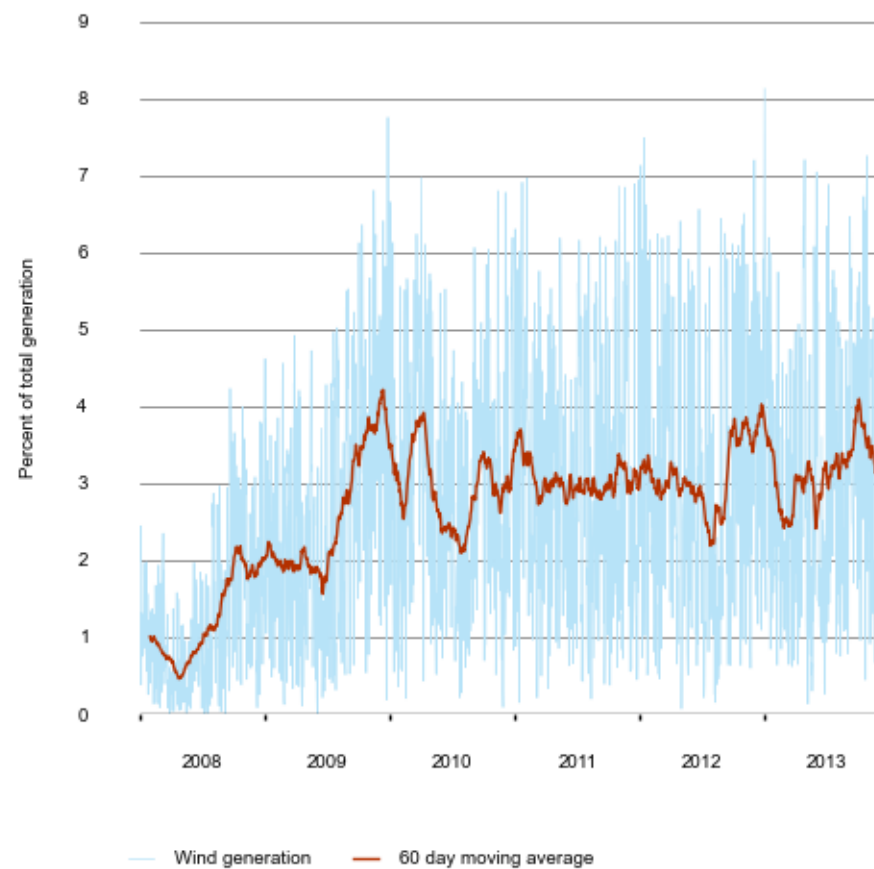
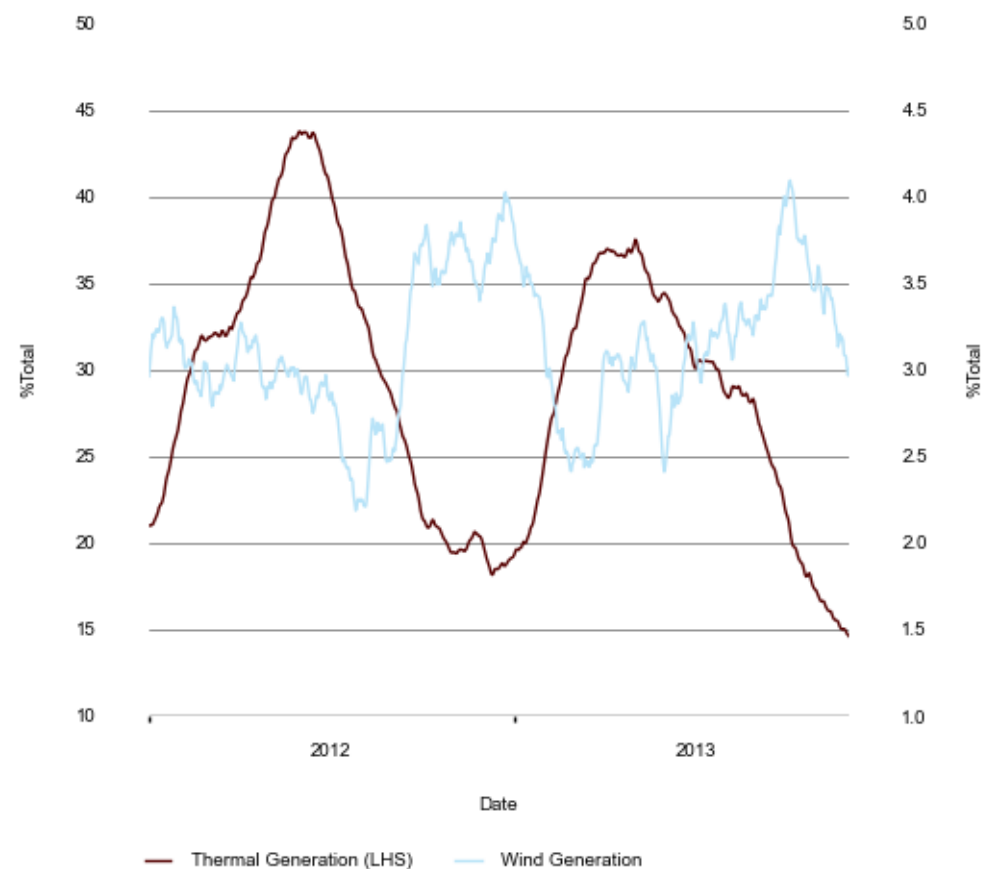


Figure 29 shows how thermal generation works to firm wind generation by showing a 60-day moving average of wind generation as a percentage of total generation and a 60-day moving average of thermal generation as a percentage of total generation. The data is for 2012 and 2013. Periods of high wind generation tend to be mirrored by low thermal generation and vice versa. Table 3 shows the correlation coefficient is -0.34, which is consistent with the relationship in the graph. The graph presents this relationship more obviously because it uses the 60-day moving average – the correlation coefficient between the moving averages in Figure 29 is -0.68.

Figure 29 Thermal generation and wind generation 60-day moving averages



Wind is essentially uncorrelated with total generation and storage, as shown by Table 3. This is expected as there is no reason to expect it to be windy when load is high or when it is raining or snow is melting.

Wind is very weakly negatively correlated to total generation to the extent of being essentially uncorrelated with total generation. This means that wind doesn't contribute to demand peaks but nor is it more likely to generate during demand troughs, which is a problem in some countries.

Wind is negatively correlated with hydro generation to the extent of being essentially uncorrelated. This implies that hydro doesn't play a role in firming wind generation over daily time periods. The correlation between hydro and wind using half-hourly data is -0.06, showing that hydro also doesn't play a role in firming wind over shorter time periods. The corresponding half hourly correlation between thermal and wind is -0.27.

We used a linear regression model to investigate the seasonality of wind and total demand. We did this by using dummy variables – one for each month of the year. Monthly dummy variables are a way of looking at the monthly averages of a series. We also used a time trend in the regression, which is a way of accounting for an increase over time, so for wind, this accounts for the increasing number of wind farms built during the period in question.

Regressing daily wind generation from 2008 onwards on monthly dummy variables and a time trend, we can see strong seasonality with the regression explaining 76% of the variation in daily wind generation. The same regression—excluding the trend—with total generation explains 99% of the variation in demand. This suggests that both demand and wind are strongly seasonal. Combined with the lack of correlation between wind and total generation shown in Table 3, this implies that wind and demand have different seasons. This can be confirmed by adding wind to the total generation regression where we find that it is insignificant in the regression. What this is probably indicating is that variation in wind generation is over short time periods and variation in demand is over long time periods, so under these circumstances changes in either series are unlikely to be related. It should be noted that while these simple regressions explain a lot of the

variation that exist in the series, the residuals are not distributed normally and a more sophisticated model would be needed for statistical inference.

Wind and prices

Wind generation is thought to lower spot market prices. Wind is bid into the wholesale market at 1 cent per MWh, so it is interesting to look at its effect on prices.

We used a regression that explains daily load weighted average prices using hydro storage, wind generation, and monthly dummy variables. The data is from July 2009 to the end of 2013 in daily resolution. Wind and total generation are measured in GWh. The monthly dummy variables are the month-specific effect on price given the effect on price of total demand and wind. As hydro storage is highly correlated to the monthly dummies, we omitted it from the regression.

Table 4 shows the results of the regression omitting the monthly dummies. All variables are significant at the 1% level and have the expected signs. The R squared statistic is 0.764 – this means that the variables listed in Table 4 explain slightly over 76% of the variation in the daily load weighted average spot price.

Because the coefficient for wind is significant and negative, the regression provides evidence to support the hypothesis that wind generation lowers spot market prices. This is expected given how wind generators must bid into the market.

Table 4 Regression results for daily load weighted average spot market prices

Variable	Coefficient	Standard error	R squared
Total generation	1.76	0.14	0.764
Wind generation	-4.07	0.55	

Generation in the future

At the end of the 2012/13 financial year, energy companies gave a consistent message about the prospects of building generation capacity in the future. The majority view was that demand would remain flat with no need for new generation in the next three to five years. Due to this flat demand, some large-scale construction is on hold and some thermal generation has been mothballed.

In August, Contact announced it was likely to defer refurbishing the 350MW Taranaki combined-cycle plant because of flat demand and increasing geothermal generation. Contact said that the plant is unlikely to close, but its running hours would be reduced to extend its refurbishment deadline. Contact has also said that it doesn't expect the Taranaki combined-cycle plant to run during the winter of 2014. In November 2013, low prices caused Contact to withdraw Otahuhu B from the market.

In September, Genesis announced it was placing a second 250MW Huntly unit into long-term storage and that the unit currently in long-term storage would be fully decommissioned and no longer available to the market. This is about a year earlier than forecast in the system operator's winter energy margin and winter capacity margin analyses.

In March, Nova Energy commissioned the 100MW McKee peaker plant. This plant's short start-up time is designed to respond to peak demand but can also function as baseload.

In August, Contact announced it would exit the development of the 168-turbine Hauauru ma raki wind farm. This 504MW development is consented with the condition it be completed within 15 years. Contact's partner, Wind Farm Development, is exploring options for a smaller development at the site. Similarly, the Castle Hill 267-turbine 860MW wind farm has a 10-year lapse period and a further 10-year construction period. Genesis said in July it is an option for future development. In contrast, Meridian's 60MW Mill Creek wind farm will start producing in 2014.

During the year, two large geothermal stations were commissioned. Ngatamariki was commissioned in July, and in October, Contact announced that the Te Mihi geothermal plant would start generating in November after delays caused by oil contamination.

In October, Nova Energy Limited (Nova) announced that it had consents for a 100MW peaker at Junction Road. In 2014 Nova will decide when to proceed with the investment.

Small-scale generation

In contrast to developments in large-scale generation, small-scale generation appears to be increasing. A number of small-scale projects have been highlighted in the news. In June, Meridian and Westpac joined forces to finance photovoltaic generation on farms through their Solar Shed offer. The package is a 10KW array, either roof or ground mounted, which costs \$28,000 (3-phase roof-mounted) and has a payback period of seven to eight years.

The project on the Makaroro River in southern Hawke's Bay is an example of small hydro generation combining with irrigation. There is a similar development in the northern Hawke's Bay, and the proposed Hurunui project also combines irrigation and generation.

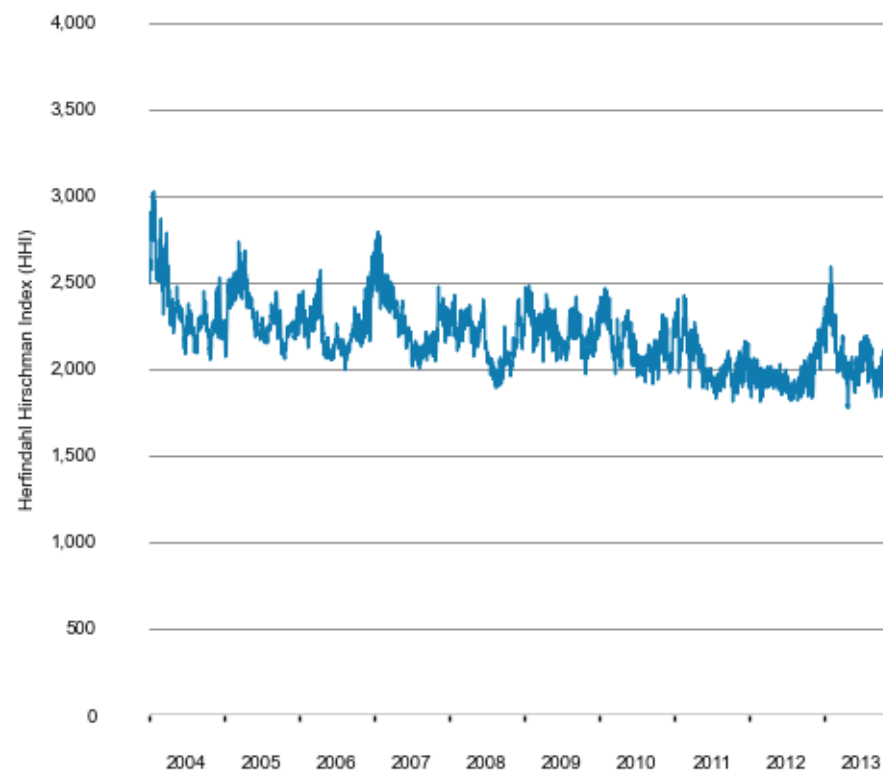
These developments may, in part, be influenced by cost reductions in the case of photovoltaic panels and increased interest in irrigation providing an opportunity to piggyback generation on irrigation dams. Either way, it will be interesting to see how this type of generation develops in the future.

The spot market is the market where generators sell their energy. We look at its structure, conduct and performance. As with the retail market, we use the HHI as an indicator of market concentration for structure. For conduct, we focused on the ability of generators to unilaterally affect market prices. Greater competition should reduce how often a generator is able to do this. Lastly, for performance we look at how the spot market responded to the drought at the beginning of the year. This is important as the spot market is the primary mechanism to signal energy scarcity and give participants all the information they need to reduce their consumption.

Spot market structure

As with the retail market, the structure of the wholesale market can easily be observed from market data. In early 2013 the HHI rose and fell dramatically. The HHI rose in January when there was plentiful water in January and hydro operators were generating at capacity. In February and March when the drought really started to bite and thermal operators began to generate, the HHI dropped dramatically. Figure 30 shows the HHI for generation since 2004. A downward trend is evident, and the data also shows a seasonal pattern with summer peaks where demand is low and hydro operators tend to generate the majority of the required energy. The chart shows that, in dry seasons – such as winter 2008 and 2012 and summer 2013 – the HHI tends to drop as thermal generation increases and hydro generation decreases which, because of the distribution of generation assets between different generating entities, has the effect of evening out market shares.

Figure 30 HHI for generation



While the national HHI for generation is low compared with the retail market, there are times when generating units are islanded and effectively the HHI in a limited geographic area is the maximum of 10,000.

A net pivotal situation

As a result of a net pivotal situation on 5 August 2013, the Authority's Wholesale Advisory Group looked into net pivotal situations and developed a proposal for a safe harbour to apply where generators are net pivotal.

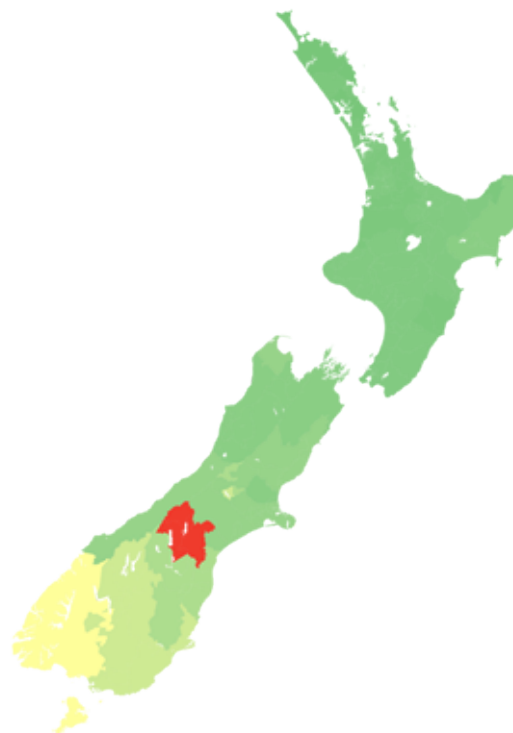
The proposed safe harbour has three principles:

- pivotal generators must offer all available generation
- prices and quantities set out in each offer must reflect the participant's genuine intentions at the time the offers were submitted
- prices for each quantity tranche must not be materially different across adjacent trading periods, except where there is a bona fide physical factor that alters the participant's capability to generate electricity between those periods.

The Authority will consider these principles and develop draft amendments to the Electricity Industry Participation Code 2010 (Code) that it plans to consult on in 2014.

Figure 31 shows prices around the country on 5 August at 9.45am. The red area represents prices in excess of \$600 per MWh. The adjacent green areas show prices of \$50–60 per MWh. The red shows the area around Tekapo and Albury with high prices that are a result of offers for generation at Tekapo A. These prices occurred over the period 5–7 August between 7.30am and about 4pm while the TIM_TKA.2 line was out for maintenance. This isolated the Tekapo A station from competition and allowed it a degree of market power for the period of the outage.

Figure 31 Tekapo islanded



Spot market conduct: market power in the wholesale market

In 2013, the Authority looked at the ability for generators to set prices in the wholesale market, and the Commerce Commission investigated market power in the South Island reserves market as a consequence of Meridian gaining offer rights to the interruptible load available from the Tiwai Point aluminium smelter in May 2012.

As in the retail market, our analysis used a well-developed list of anti-competitive conduct available from competition policy and practice – we took the approach of ensuring that anti-competitive conduct is absent. We looked at market power in the wholesale market using two methodologies.

Following on from 2012, we extended our analysis of residual supply in the spot market from January 2010 to September 2013 by altering actual offers to get an idea of the ability generators have to reduce supply and raise price. The methodology is the same as described in last year's review (www.ea.govt.nz/industry/monitoring/reports-publications/annual-reviews/) and follows the work of Wolak (www.comcom.govt.nz/investigations-reports). It involves two scheduling pricing and dispatch solutions (using vSPD – the vectorised scheduling and dispatch model available on the Authority's website), a base case and a counterfactual where 50MW is taken from the lowest price band for each trader and placed in the highest price band. We did this analysis for the five largest generating companies and assumed no alternating current transmission constraints.

The methodology for TrustPower was different for the South Island because, during the dry season early in the year, TrustPower often wasn't dispatched for as much as 50MW in the South Island. Therefore, for TrustPower in the South Island, 10% of the dispatched energy from the base case was used instead of 50MW.

For each pair of vSPD solutions, we calculated the change in weighted average price divided by the change in quantity supplied. This was each trader's ability to influence price by changing the structure of their offers to the spot market.

We also calculated the change in profit for each scenario as a measure of the incentive to raise prices by changing the structure of offers. Our measure of conduct is the correlation between the ability to influence prices and the quantity weighted average

offer price – this should show the propensity for generators to raise their offers when they are in a position to influence price.

In a less subtle variation on the methodology reported in the 2012 year in review, we also used vSPD to simulate what would happen to the market price if a single participant raised its offer prices to unusually high levels. Specifically, for each of the large vertically integrated generator/retailers, we ran a simulation where we raised their energy and instantaneous reserve (IR) offers to \$30,000 and measured the amount of their energy that was dispatched, which we have called their gross pivotal amount.

We then estimated their contracted load using purchase data from the reconciliation manager, the virtual asset swap agreement, hedge disclosure data and an estimate of the Meridian NZAS contract load. We subtracted this estimate of contracted load from the gross pivotal amount to get the net pivotal amount.

If the net pivotal amount is greater than a threshold – we use 50MW, this case (trading period, trader) is counted as a case where the trader is net pivotal.

Results: Wolak method

To assess market conduct, we used the correlation between the ability to influence prices and the quantity weighted average offer price.

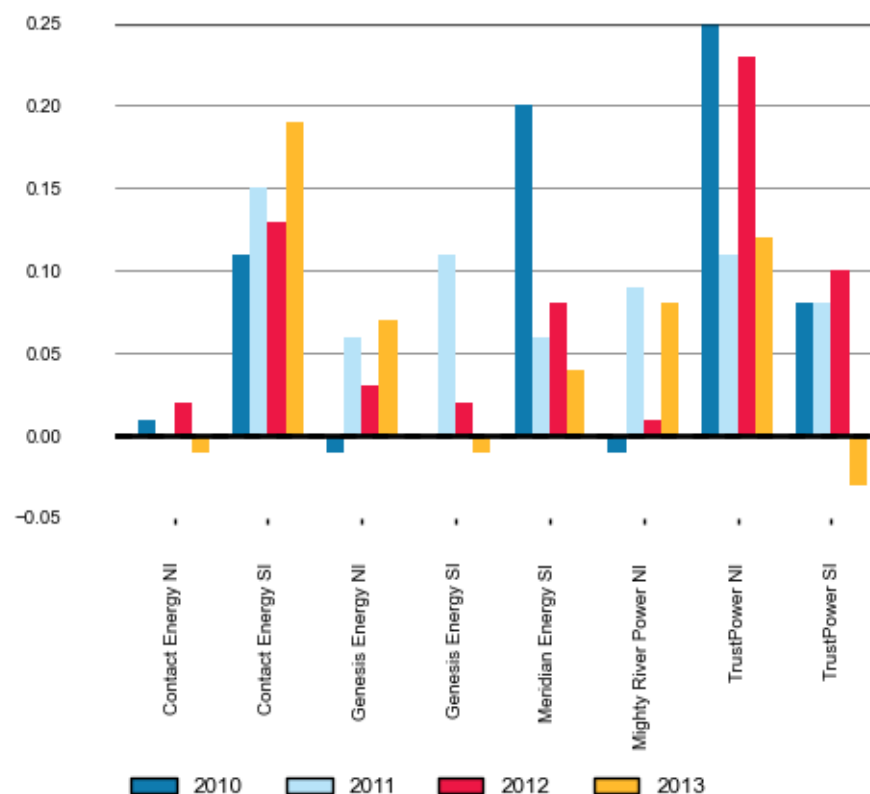
We found weak correlation between the offer prices and the ability to influence prices for 2013. This is the same measure as reported in the 2012 year in review.

Very low correlations could indicate generators with a contracted load close to their generating capacity and therefore their objective is to get dispatched, so their offers are unlikely to vary with their ability to affect price. Generators that have a large proportion of wind and/or geothermal generation – which is bid into the market at low levels to ensure those plants are dispatched – could lead to very low correlations simply because of the lack of variation in offers.

Higher correlations may mean that a hydro generator is conserving water, raising offer prices and therefore having more offers around the cleared price, so the causality is fuel shortage causing higher offers that increase the generator's ability to affect price. For a thermal operator, it's easy to imagine a scenario where the price is rising to the level that they need to start or ramp up generation and they use their offers to determine the extent to which they can do this. This would be the case if fuel was progressively more expensive or the generator was progressively less efficient as output increased.

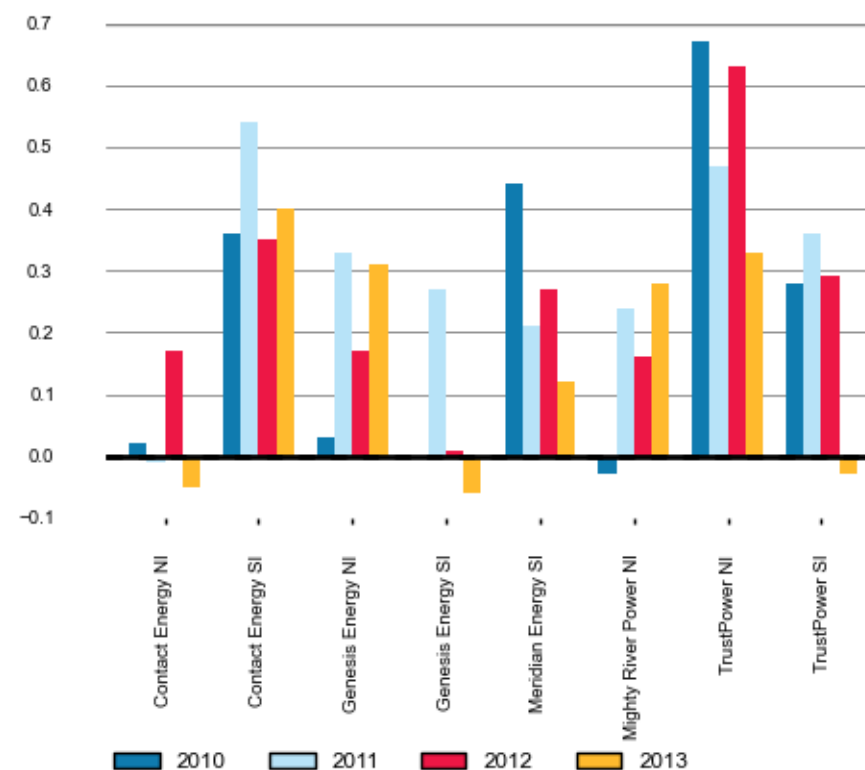
The correlations for trading period data are set out in Figure 32. We also used the same measure for daily data which shows much higher correlations (Figure 33). Daily correlations may be higher than the half-hourly correlations simply because there is more time for coincident changes in the ability to affect price and the quantity weighted average offer to be picked up by the measure. It is inevitable that, in any half hour, there will be a marginal generator in one or both islands, and quantity weighted average offers rise and fall during the day as generators seek to cover their contracted load, so it is possible that there is some spurious correlation in this measure.

Figure 32 Correlations between the ability to influence price and the quantity weighted average offer for the five largest generators by trading period



Both measures show a great deal of variation within and between individual generators. It is not obvious whether this is due to variations in circumstances or variations in offer strategy. This sort of simulation modelling is an area that the Authority plans to work on in the future.

Figure 33 Daily correlations between the ability to influence price and the quantity weighted average offer for the five largest generators



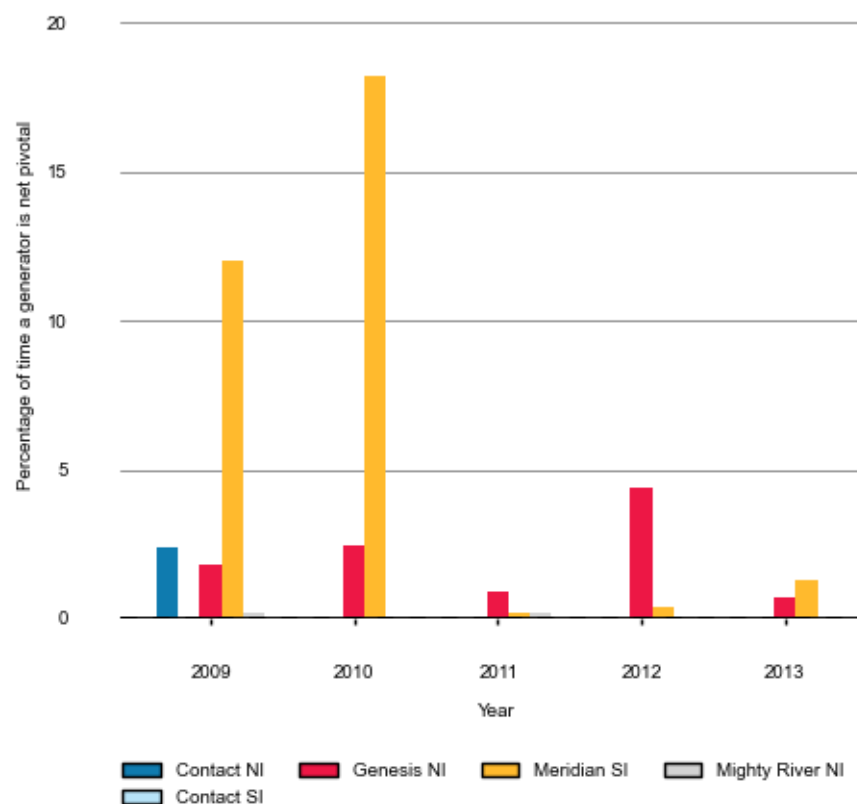
Results: net pivotal analysis

Figure 34 shows the results for the net pivotal analysis in terms of the percentage of trading periods that each generator is net pivotal. This means that they would be profitably dispatched despite lifting all their offers to \$30,000. Figure 34 shows that the amount of time each generator is net pivotal is falling and is at very low levels. The experiment returned zero results for a number of generators.

The large drop in Meridian's net pivotal count since 2010 is likely to be due to the virtual asset swaps from 2011 and an increase in futures contracts. The virtual asset swaps affected Meridian's ability to be net pivotal in the South Island by reducing its virtual generation capacity there. Increased contract volumes also reduce the net pivotal count because the more contracted volume a generator has, the less likely it is to be able to make a profit from lifting its offer price.

We think that the increase in Genesis's 2012 North Island count is due to lower imports from the South Island as the HVDC Pole 1 was decommissioned, an extended outage of its Otahuhu thermal plant in 2012 and its lower North Island retail load.

Figure 34 Net pivotal count for large generators



Spot market performance: managing summer drought

The early part of 2013 saw a dramatic turnaround in storage in the South Island. Figure 35 shows daily storage and price in the first five months of 2013. Storage is measured as South Island storage as a percentage of mean and the price is measured as a daily load weighted average. The horizontal line is 100% of mean storage. Figure 35 shows the dramatic fall in storage during the first four months of the year. In January, storage was over 40% higher than average, and by late April, it had fallen to nearly 30% below average. The spot market reacted in late February as storage fell below average.

Prices settled during late March and April as inflows began to stabilise storage and the drought eased. Storage eventually climbed above average in early July.

The chart shows that prices signalled that water was scarce as they leapt from about \$50 to over \$300 on some days. This price response is a signal that fuel is short so load should cut back, and thermal generation should increase.

In some senses, the main function of a market is to summarise information so that traders do not need to understand the fundamentals that drive price changes – they only need to understand the implications of those price changes. This means that the information needed to make decisions is drastically reduced from the huge number of things that affect the price to just knowing that price.

In the context of the wholesale market, this function is most clearly seen when water for hydro generation is scarce and thermal generators become commercially viable. Thermal generators don't respond to hydrology, but they respond to price, so a measure of performance is that the market responds to dry conditions as expected.

Figure 35 Storage and demand weighted average price in early 2013

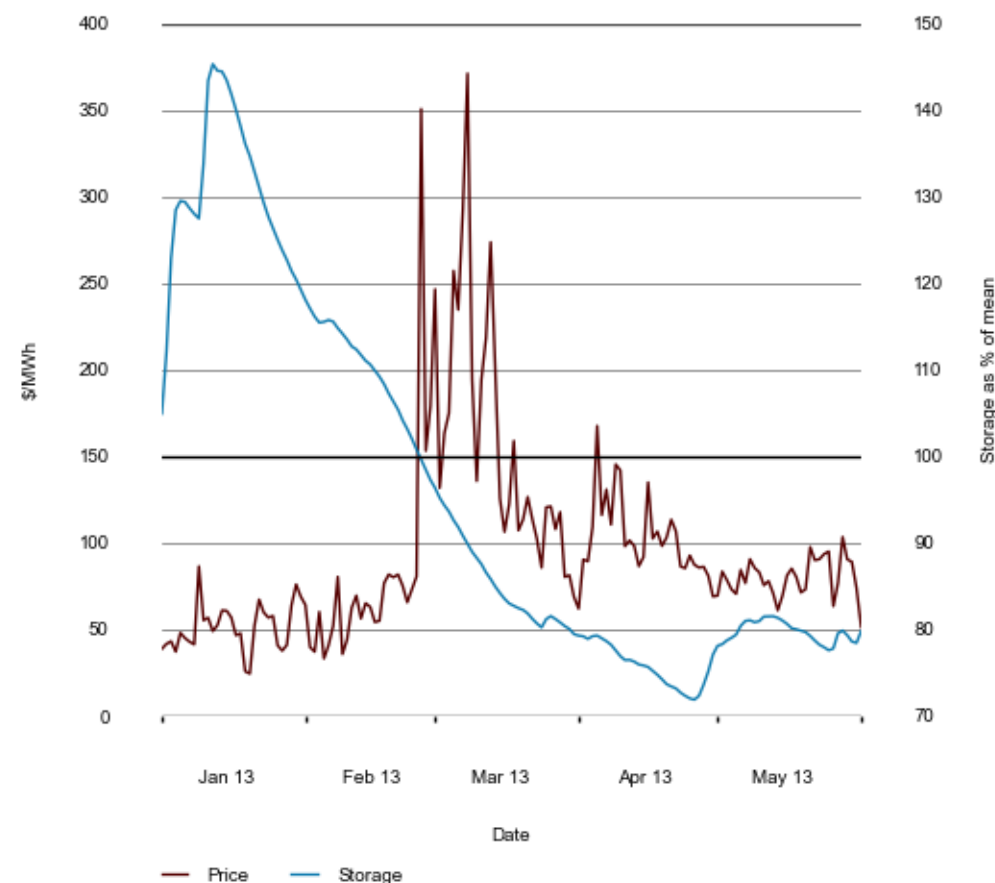


Figure 36 shows how thermal generators responded to the increased price. The price for the 96 days from the time that storage fell below 100% of mean storage on 25 February until the end of May averaged \$117 per megawatt hour.

Figure 36 Thermal generation and price early 2013

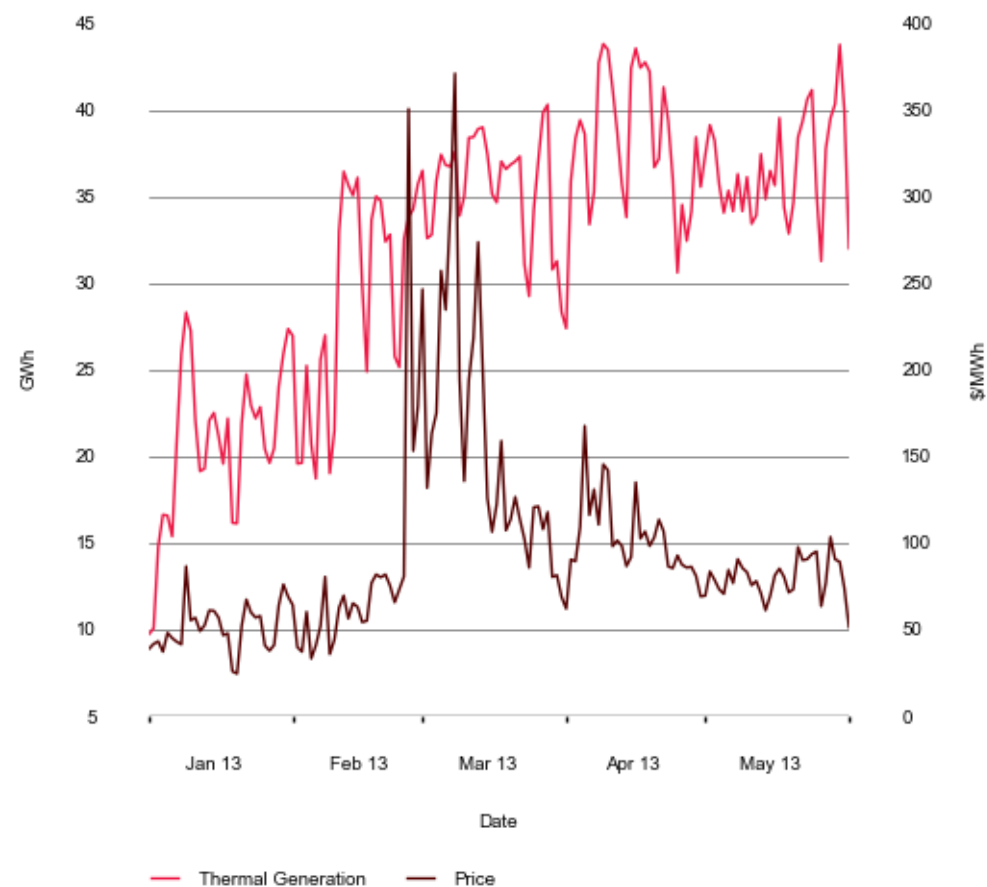
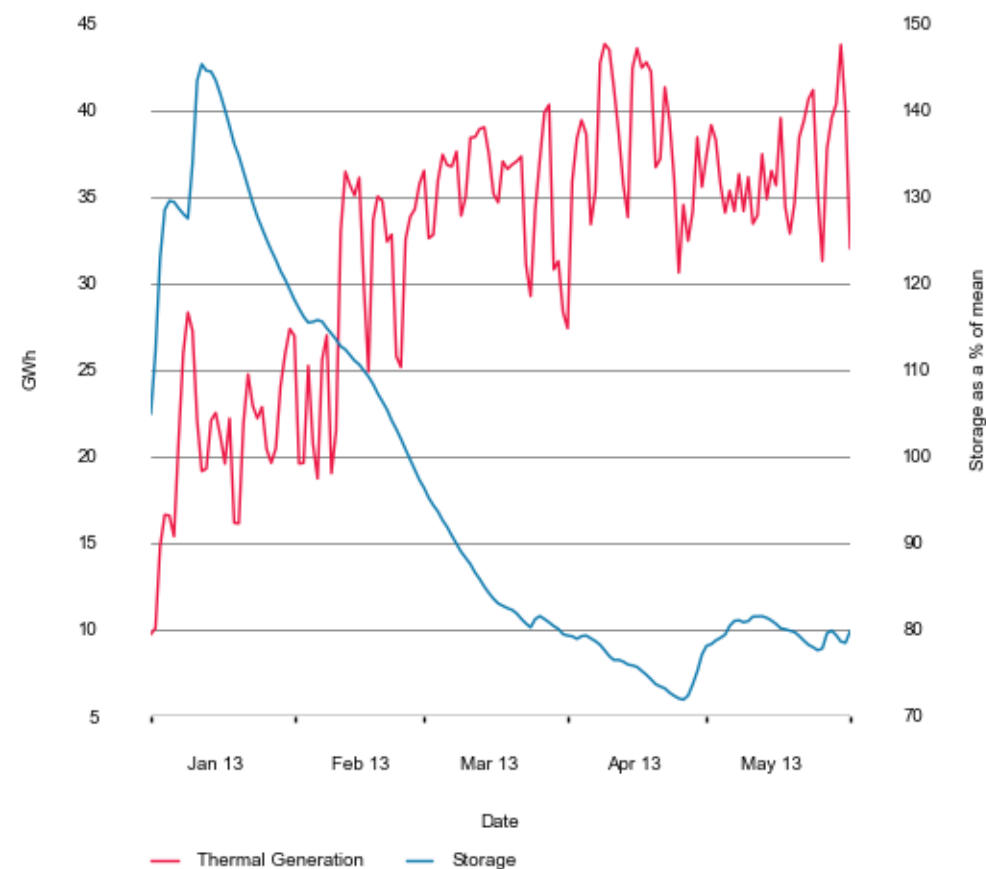


Figure 37 shows the relationship between thermal generation and hydro storage. As storage fell, thermal operators increased their output. Again, this is an appropriate market response to scarce resources. This is consistent with Table 3 above, which shows the correlation coefficient between thermal generation and storage is -0.63, which means that low storage coincides with high thermal generation output.

The direction of the reaction of price to scarce hydro storage is what we would expect. The thermal response to the high price is also how we would envisage a workably competitive market to operate.

Figure 37 Storage and thermal generation early 2013



Investigation into South Island reserves

Early in 2012, Meridian acquired the offer rights for 165MW of interruptible load at the Tiwai smelter from NZAS. This created a block of interruptible load equivalent to 70% of the volume on the South Island IR market. On 9 May 2012, the price for 70% of South Island fast instantaneous reserves (FIR) increased from less than \$1 per MW to over \$150 per MW due to a change in offer strategy. This increased the cost of covering an HVDC contingent event and led to a price separation of the North and South Island spot prices and the ASX hedge prices for the winter quarters.

The Authority's market performance team investigated the high South Island IR prices. The investigation concluded that the high South Island IR prices caused higher energy prices in the South Island (13%) and lower energy prices in the North Island (14%) relative to a counterfactual where South Island IR prices didn't spike. The investigation also concluded that the spike in South Island IR prices caused a separation in ASX hedge prices. The net cost of this was relatively low at \$1.3 million. The full report is available at www.ea.govt.nz/industry/monitoring/enquiries-reviews-investigations/2012/.

The report was handed over to the Commerce Commission to investigate whether there was a breach of competition law.

The Commerce Commission concluded that:

- Meridian did not breach section 27 of the Commerce Act 1986 because NZAS was able to exercise its countervailing power to quickly exit the contract for interruptible load and the purpose of the contract was unlikely to have been to substantially reduce competition
- the short duration of the high prices was unlikely to constitute a substantial lessening of competition because it was transitory
- the purpose of the contract was to enable Meridian to offer interruptible load into the reserves market and that there was no subjective or objective evidence that the purpose of the contract was to reduce competition
- Meridian didn't breach section 36 of the Commerce Act for similar reasons to those above – there was countervailing power and no evidence of an anti-competitive purpose.

Investment performance: transmission

In October 2012 the Authority proposed a new methodology for transmission pricing. This involved using vSPD simulations to determine the beneficiaries of transmission assets. As an experiment, we used a variation on this methodology to determine the value to the market of a hypothetical North Island Grid Upgrade project (hNIGUP). The real North Island Grid Upgrade project (NIGUP) was commissioned in September 2012. We used the period prior to commissioning – from 2008 to September 2012. The research asked how much value the hNIGUP would have yielded during this period if it was built sooner.

To do this, we simply used the difference in the objective function for two vSPD solves – one with hNIGUP and one without hNIGUP. The objective function is the cost of energy that vSPD minimises, so the idea is to measure the reduction in cost to the system that the asset causes.

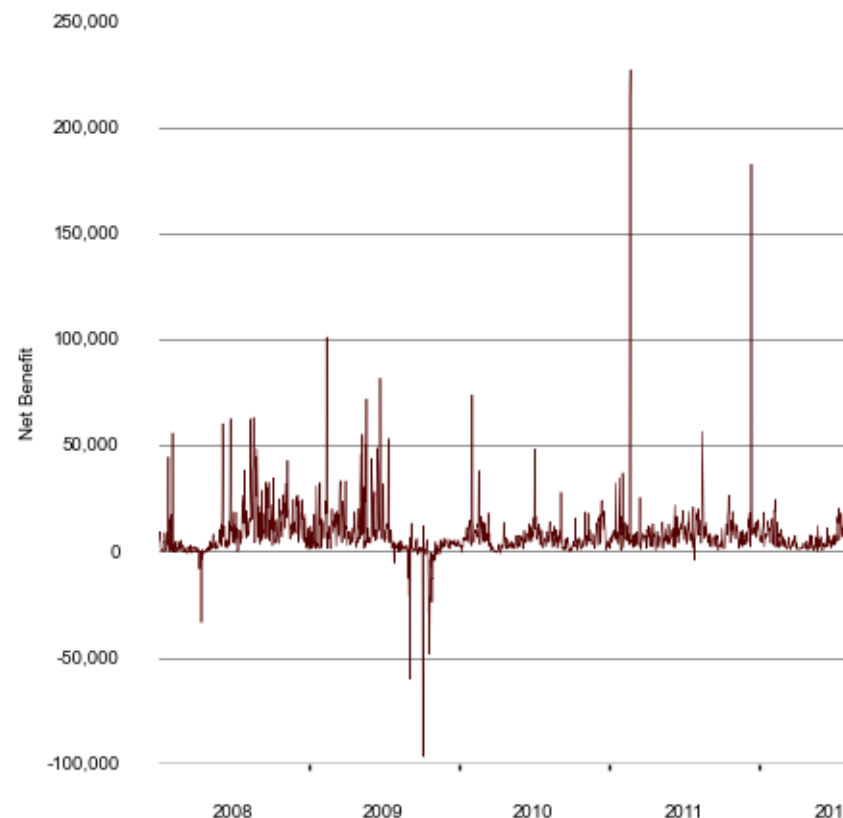
We filtered out 26 March 2011 as this was an obvious outlier in the data caused by a transmission outage and some very high prices in the North Island.

Figure 38 shows the net benefit of hNIGUP over this period. The chart shows that the benefits are volatile and not always positive. The mean benefit is \$8,023 per day and the standard deviation is \$13,001. The highest daily benefit is \$227,009 and the lowest is -\$96,735. In total over the four years, the asset provided a total benefit of \$13.7m. With 26 March included, this rises to \$15.6m.

The mean annual benefit is \$2.75m. By way of contrast, assuming a 40-year lifetime and using Transpower's WACC of 7.7%, an annual benefit of \$67m is equivalent to the capital cost of \$824m. This calculation doesn't take into account the benefits from improved reliability that any transmission asset provides.

This is a demonstration of how we intend to use vSPD simulations to assess investment performance. Assessment by the Authority is important because of the longevity and huge cost of many assets in the sector.

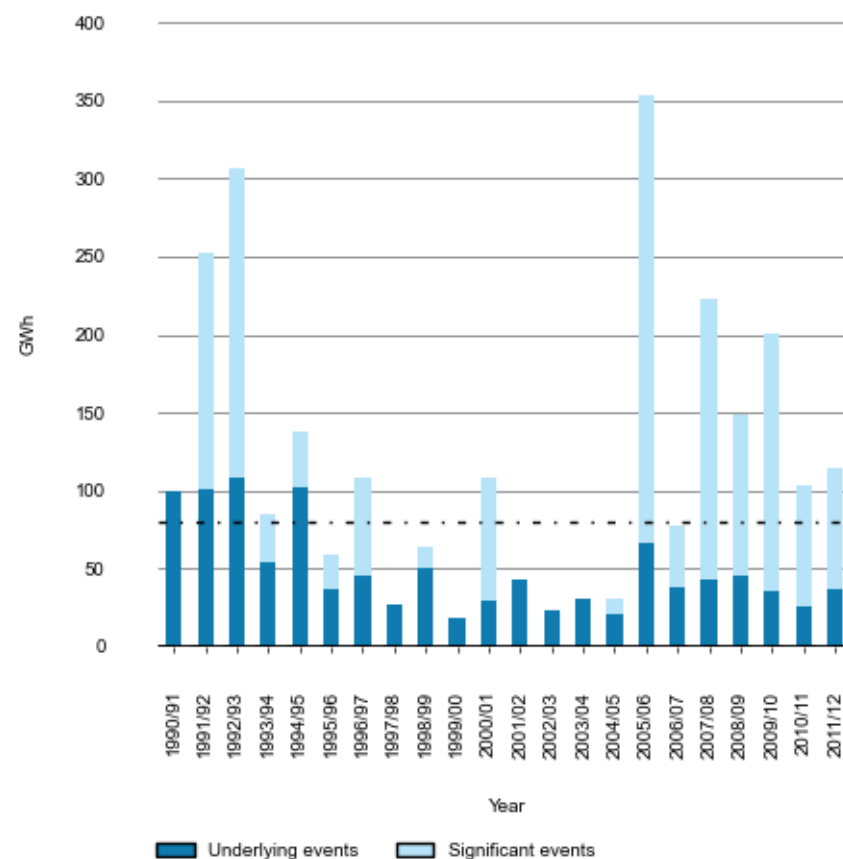
Figure 38 The net benefit of a hypothetical NIGUP from 2008–2012



We have continued with our index of transmission outages we used in 2012. The fault data in Figure 39 comes from the system minute fault data published by Transpower in its annual Quality Performance Report. It starts by taking the system minutes of outages and dividing this by peak energy for that year, which gives unserved energy. This unserved energy is divided by total delivered energy for the year. This is indexed to 100 for the 1990/91 year. The horizontal line is the 2010/11 target calculated as 2010/11 system minutes and indexed the same way as the fault data.

Figure 39 shows that 2011/12 – the latest year we have data for – is similar to 2010/2011, which itself was a large improvement over four of the previous five years.

Figure 39 Transmission outage index



Avoiding cascade failure

Automatic under-frequency load shedding (AUFLS) is the last line of defence for the electricity system. The AUFLS system is designed to trip off selected load in response to a deep drop in power-system frequency. The purpose is to prevent generation from tripping off to protect itself, and therefore avoid a cascade failure.

The AUFLS system exists to guard against the possibility of a chain reaction of generation needing to trip off. Generators will trip off to protect against damage that might occur if the frequency of the network they are connected to drops too far. If generation was to trip off, the frequency would drop further, and there is a risk of a cascade failure leading to total non-supply, from which it would take a substantial time to recover.

The November AUFLS incident was the second in two years caused by incorrect protection settings. This is clearly a cause for concern for the sector given the potential consequences.

November 2013 AUFLS event

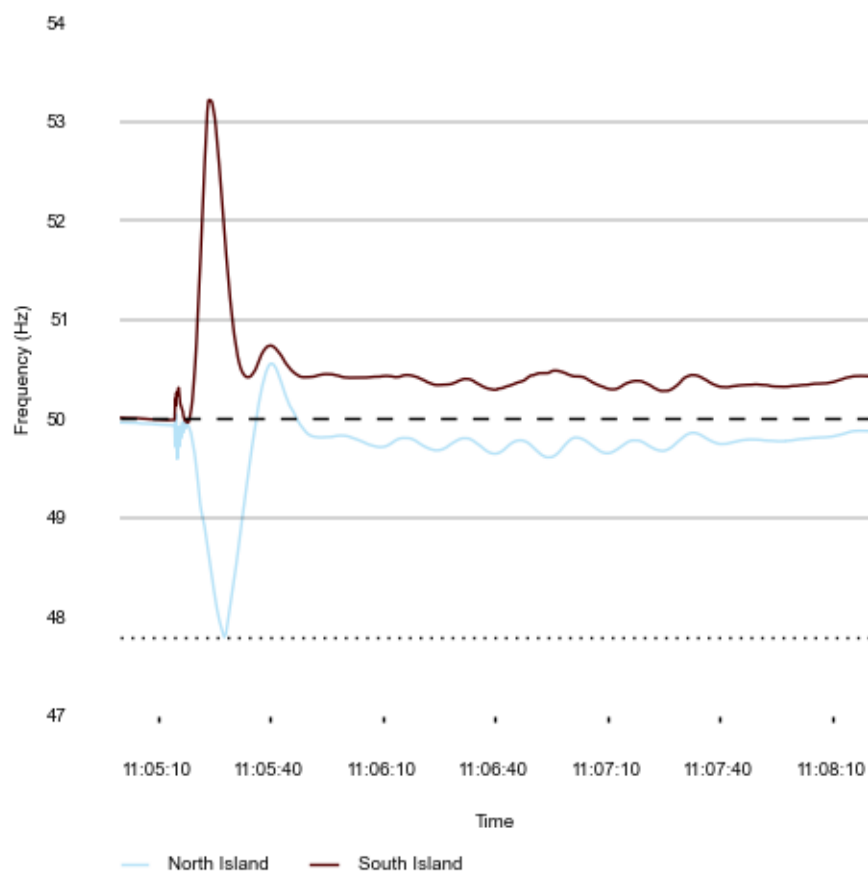
On 12 November at 11.04am, the HVDC quickly reduced northwards transfer from 1,024MW to 145MW because three filter banks at Benmore disconnected due to faulty protection settings. This happened during a test of the HVDC, which involved faulting the AC system near to Haywards. The objective of the test was to ensure that the HVDC was robust to such a fault.

The test affected voltage at the other end of the HVDC at Benmore as expected. However, this voltage disturbance caused three 220kV AC filter banks at Benmore to trip because of incorrect protection settings. This, in turn, caused the HVDC to automatically reduce the amount of energy being transferred north.

The sudden loss of so much energy caused the North Island frequency to drop sufficiently to partially trigger the first block of the AUFLS relays. These relays disconnected 401MW of North Island load (about 12% of the electricity being supplied at the time). A further 204MW of interruptible load was also disconnected as IR.

Figure 40 shows a trace of the frequency in the North and South Islands for just before and after the AUFLS trip. The frequency drop that caused the AUFLS relays to trip in the North Island is very clear from the trace. The dotted horizontal line in Figure 40 is the frequency at which the first block of AUFLS is supposed to trip and disconnect load causing power cuts and protecting the system from the consequences of sustained low frequency. The dashed line is where the frequency ought to be – 50Hz.

Figure 40 Frequency trace for the North Island for 12 November before and after the AUFLS event



The AUFLS worked as it is designed to, disconnecting about 12% of national load at the time. This affected approximately a quarter of a million customers throughout the North Island.

The previous AUFLS trip was at Huntly, where incorrect protection settings caused the station to disconnect from the network.

Protection equipment is extremely reliable and nearly always functions as it is designed to do, but over time, protection systems have become increasingly complex so that errors in the design of the systems are not apparent. This can cause unforeseen protection responses to unusual circumstances. What has happened in the last two AUFLS events is that the protection was subject to abnormal events, it performed as designed and an AUFLS event happened.

Although engineers design protection systems conservatively to contain complexity and prevent cascade failure, it is evident from the recent history of AUFLS events caused by incorrect protection settings that there is room for improvement.

Part of the Authority's function is to look into events to discover what happened and whether there is a need to change any regulation to improve outcomes. The Authority undertook three enquiries in 2013, summarised below.

High spring washer price situation

On 20 June 2013, during trading period 41, the final spot electricity price at Lichfield and Kinleith reached \$8,318/MWh and \$6,466/MWh respectively due to a binding transmission security constraint. The high spring washer price resolution process was invoked, which marginally affected prices in the region.

The circumstances that contributed to the high spring washer price situation were:

- closing the Arapuni bus split
- transmission outages
- the HVDC tripping
- the Kinleith cogenerator tripping
- high demand caused by a very cold southerly storm.

The two main issues in the report are closing the Arapuni bus split and Transpower's associated net benefit test for doing so and the use of static line ratings that assumed temperatures that were far higher than those that prevailed on 20 June 2013. This reduced the line ratings compared to a hypothetical scenario where the line ratings are based on actual temperatures.

The Authority has found that, while the decision to temporarily close the Arapuni bus split was correct, the process of consulting with and notifying affected parties could be improved. The Authority will further consider these issues as part of its review of Part 12 of the Code.

Using static line ratings to calculate final pricing separates the economic model of the network from the physical reality. In this case, our modelling shows that transmission circuits that were binding in final pricing could safely carry 20% more load because of the very cold weather. Had line ratings been adjusted to reflect the actual temperature,

the high spring washer price situation would not have occurred. This is inefficient because the model used in dispatch does not closely match reality and therefore the model is allocating resources inefficiently.

Line ratings that more realistically reflect actual circumstances could be applied to the high spring washer price resolution process, but this would mean that final and forecast prices would diverge, creating a different problem for participants.

Transpower has considerable knowledge of dynamic line ratings but is yet to implement them. It gained substantial experience in the use and benefits of dynamic line rating from trials it undertook in the late 1990s. Transpower has not made progress in deploying dynamic line rating methods in the intervening 15 years, despite the substantial benefits available to grid users and the comprehensive deployment of the technology in other locations, such as Tasmania.

Transpower is considering increasing the accuracy of its static line ratings to more closely reflect historical conditions for the time of day and year. It is also undertaking a dynamic line rating trial in 2014.

There are no barriers to dynamic line ratings in the Code.

Full details of this enquiry can be found at www.ea.govt.nz/industry/monitoring/enquiries-reviews-investigations/2013/.

Pole 3 and Ngatamariki commissioning

The key issue associated with commissioning is where the costs fall. To a large extent, the commissioning costs are socialised to participants in general. An important question is whether allocating these costs to the commissioning party would lead to lower overall commissioning costs. This would occur if less costly ways to commission plant were chosen because the commissioning party faces the costs of commissioning. The report recommends looking further at the issue to see if there are more efficient ways to allocate commissioning costs.

The HVDC Pole 3 and the Ngatamariki geothermal station were both commissioned during 2013, and the Authority's market performance team undertook an enquiry into the market impact of the commissioning process with a focus on where the costs fell.

The Pole 3 testing required additional reserve requirements and constraints that at times affected final pricing. We estimated the cost of the commissioning by using the vSPD model to simulate the market outcomes that would have occurred without the test-specific constraints and requirements. Specifically, we removed flow constraints on Pole 2 and minimum flow constraints on both poles and removed the HVDC as a secondary risk.

The Authority understands that HVDC testing was accomplished using a range of contracting arrangements. These arrangements are likely to have affected the distribution of costs between participants, reduced the wholesale market impact and affected the offers that were in place in the market at the time. Consequently this analysis measures the incremental impact of commissioning given that these contracts are in place.

The Authority estimates that the constraints, outages and additional reserves dispatched to facilitate the testing of HVDC Pole 3 resulted in a \$6.3m increase in load costs and a \$57,000 increase in reserve costs over the test period from 16 February 2013 to 29 May 2013. This represents 0.5% of the load costs and 0.6% of reserve costs respectively over that period.

Commissioning Ngatamariki required increased dispatched reserves because of the reduction in net free reserves caused by Ngatamariki being considered a secondary risk for the period of its commissioning.

The Authority estimated the impact of the additional reserves by removing these additional reserves from the net free reserves inputs and recalculating the final market prices over the period from 20 March 2013 to 23 July 2013. Full details of the methodology used for the HVDC and Ngatamariki commissioning can be found at www.ea.govt.nz/industry/monitoring/enquiries-reviews-investigations/2013/.

High prices in February and March 2013

Figure 35 above shows the steep fall in storage early in 2013. This was accompanied by an increase in spot price. During this time, a number of other factors pushed prices higher. These included the Tekapo canal repairs, which meant that the Tekapo power stations were unavailable, and the Taranaki combined cycle (TCC) plant was on a planned outage for maintenance from 21 February to 26 March 2013.

Storage fell from mid-January after very high South Island inflows in early January. Lake Taupo was already below average at the start of 2013 as a result of lower than average inflows in 2012. These continued in early 2013, and by the end of February, Lake Taupo was at 65% of its mean storage and falling.

Figure 35 shows the national demand weighted average price and South Island storage as a percentage of mean for the first five months of 2013. It shows the steep fall in storage and the corresponding increase in price in late February and early March. National demand weighted average prices began to increase from late February, peaking on 8 March at \$370/MWh. As the chart shows, prices then fell later in March until they returned to more normal levels in April and May. Storage recovered from about 70% of mean in late April to 80% by the end of May. Figure 24 shows that storage climbed above mean in July where it remained for the rest of the year apart from a small dip in October.

The fall in storage early in the year was accompanied by an increase in ASX futures prices. These peaked on 8 March at around \$120 for the June quarter for both Benmore and Otahuhu futures. Prices were high for the two winter quarters at Benmore, but the September quarter Otahuhu prices were more in line with the outyear prices so seemed to reflect long-term expectations rather than the storage situation that existed at the time.

These high prices induced thermal generators to increase output. Figure 37 above shows thermal generation and national storage as a percentage of mean. It shows how thermal generation trended upwards from the beginning of 2013.

Figure 36 above shows the relationship between thermal generation and load weighted average spot prices. It shows how thermal tends to react to high prices, which is exactly what we would expect given the high marginal cost of thermal fuel.

The Authority undertook an enquiry into the events of early 2013, which is available at www.ea.govt.nz/industry/monitoring/enquiries-reviews-investigations/2013/. The enquiry highlighted five issues, some of which have been noted previously and are being addressed through various projects:

- Generators with the ability to affect wholesale prices undermine efficiency. This is being considered by the Wholesale Advisory Group through the pivotal supplier project.
- Final prices deviating from forecast prices affect participants' ability to make decisions in real time, undermining efficiency. This is being addressed by the Wholesale Advisory Group is considering this as part of the pricing alignment project.
- Forecast prices not being available at times affects participants' ability to make decisions in real time, undermining efficiency. This issue is being considered by the Wholesale Advisory Group.
- Commissioning assets can affect market prices and price volatility, hindering decision-making. The Authority is undertaking an enquiry into the commissioning of the HVDC to see what lessons can be learned for commissioning in general. This is discussed above.
- Generators using offer prices to prevent transmission constraints from binding can lead to inefficient dispatch. The Authority is considering a project looking at within-island basis risk as a possible alternative to this behaviour.

