



ELECTRICITY MARKET PERFORMANCE

2014 YEAR IN REVIEW

PURPOSE OF THIS DOCUMENT

This review highlights important events and trends in the electricity market during 2014.

It provides an overview of the performance of the electricity market and is intended for industry or other interested audiences.

This review covers the 2014 calendar year.

This is the fourth time the Electricity Authority has published an electricity market performance year in review.

EXECUTIVE SUMMARY

In 2014 the electricity market continued to demonstrate many of the trends we observed in 2013. Energy demand remained flat; the retail market made further progress in relation to competition and innovation, and the wholesale market was marked by high activity within the hedge market. Again in 2014 we experienced dry periods that were very well managed by generators.

THE RETAIL MARKET'S CONTINUED POSITIVE TREND

In 2014 we continued to observe a positive trend toward increasing competition across the structure, conduct and performance elements we measure. Particularly notable in 2014 was the decrease in retail prices in the competitive part of the sector in the September and December quarters.

Customers enjoyed the almost universal practice employed by retailers to offer prompt payment discounts with most offering around the 15 per cent mark. Another customer incentive offered by retailers was joining credits, which were generally valued between \$100 and \$200.

Again in 2014 we saw that customers were focused on finding the best electricity deal for their needs. Forty thousand account changes took place in March 2014—a 33-month high and the second highest month ever for switching. We undertook a consumer-targeted survey, which confirmed financial reasons were the biggest motivator for a switch. Generally, competing retailers approached switchers, as opposed to switchers actively approaching another retailer to discuss a potential switch.

The implementation of smart meters is ongoing, with more than half of the country's two million meters now smart meters, and innovations are beginning to occur through the use of this technology.

NEW PRODUCTS AND PROCESSES IN THE WHOLESALE MARKET

It was an exciting year for the wholesale market. The hedge market experienced increased activity in ASX traded hedges and fixed price contracts.

The increased activity in the hedge market is a reflection of the preferences of market participants. We've received data that indicates a change has occurred in the type and quantity of products being traded in the market. This growth in the range of products is positive as it means participants have more choice around the most appropriate instruments for the market conditions.

New products implemented late in 2013 have been successfully absorbed into the market, although trading volumes for these products are low. These products include new monthly baseload futures, quarterly peak load futures and quarterly options, with all products providing more choices to hedge risk.





Financial Transmission Rights (FTRs) were introduced for two nodes in 2013—FTRs are a locational hedge product used to manage price risk on the national transmission grid. At the moment, we're monitoring the take-up of FTRs to identify if participants are purchasing a large proportion of the available FTRs. In 2014 we saw the introduction of three new nodes.

A key focus in 2014 was a review of multiple frequency keeping in the North Island. The review of the initial rollout in the North Island was carried out to help inform further development in this area.

GENERATOR CAPABILITY, DYNAMICS AND BEHAVIOUR

Generators continued to demonstrate their capability in effectively managing a dry summer using the spot market and high voltage direct current (HVDC) transfers. New Zealand experienced a dry summer in 2014, but despite these conditions, hydro generation exceeded the outputs of the previous year.

The dynamics between generators in the wholesale market shifted in 2014, with the commissioning of two geothermal generators.

These changes meant that, in 2014, 79.7 per cent of New Zealand's generation came from renewable sources (hydro, geothermal and wind).

With the introduction of trading conduct provisions in 2014, we have been paying close attention to the spot market and whether generators are behaving in line with the standards set as ideal trading conduct.

COMPLETED AND ACTIVE MARKET PERFORMANCE ENQUIRIES

In 2014 we completed four enquiries on market and reliability events. The enquiries are outlined in section 5.

In addition to these completed enquiries, we're currently progressing five further enquiries on metering, frequency keeping, the fire at the Penrose substation in October, the under frequency event in November 2013 and retailer behaviour regarding switching and saves.



SECTION 1: ENERGY DEMAND

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Energy demand in 2014 increased moderately but remains lower than in 2010. We have investigated whether this trend is the result of any structural changes in the economy.

MONTHLY DEMAND LEVELS COMPARED TO 2008-2013

We graphed monthly energy demand for 2014 and compared it to the mean monthly energy demand between 2008 and 2013. The Tiwai Point aluminium smelter accounts for around 15 per cent of all electricity use in New Zealand, which means changes in its demand can obscure changes from other consumers. To get a complete picture of what is happening with energy demand we assess it both including and excluding Tiwai's use.

Figure 1: 2014 energy demand excluding Tiwai

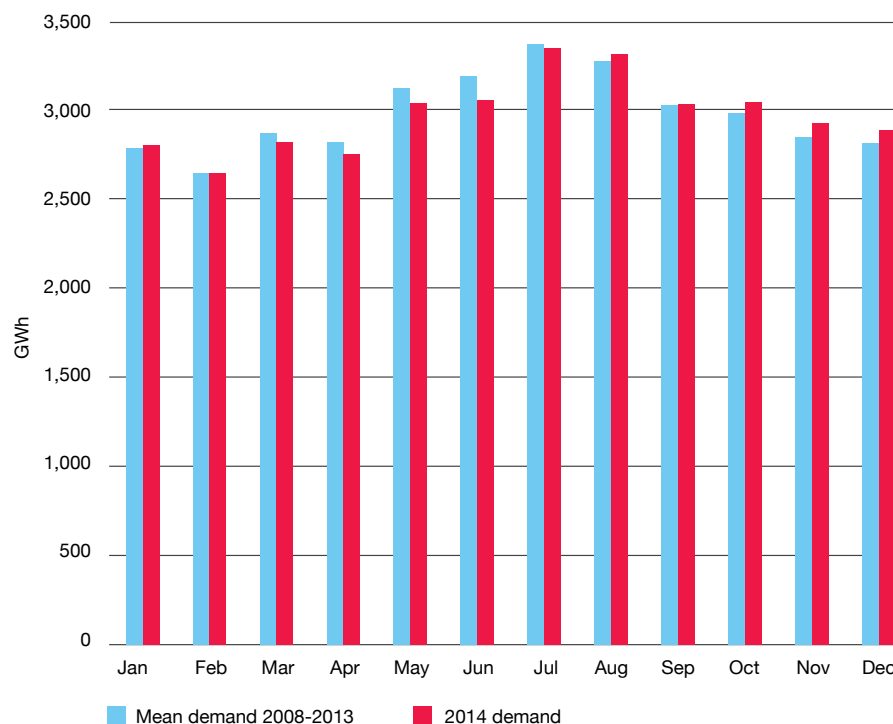


Figure 1 shows 2014 energy demand excluding Tiwai. Higher prices in mid-autumn, and winter weather may explain the lower demand experienced in the first half of the year. Dry conditions late in 2014 may have caused higher irrigation load, accounting for the relatively high consumption from October to December 2014.



Figure 2: 2014 demand at Tiwai compared with previous years

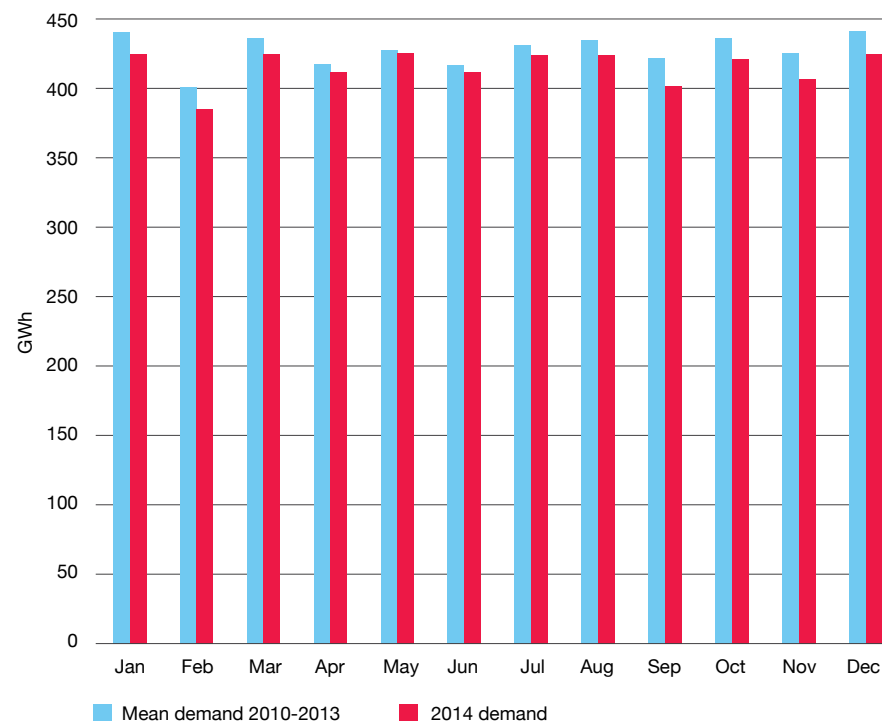


Figure 2 shows Tiwai's monthly demand compared with its mean demand in 2010-2013. The chart illustrates that Tiwai demand has fallen in all months compared with previous years. This explains some of the fall in total demand illustrated in figure 3.



Figure 3: Total demand compared with previous years including Tiwai

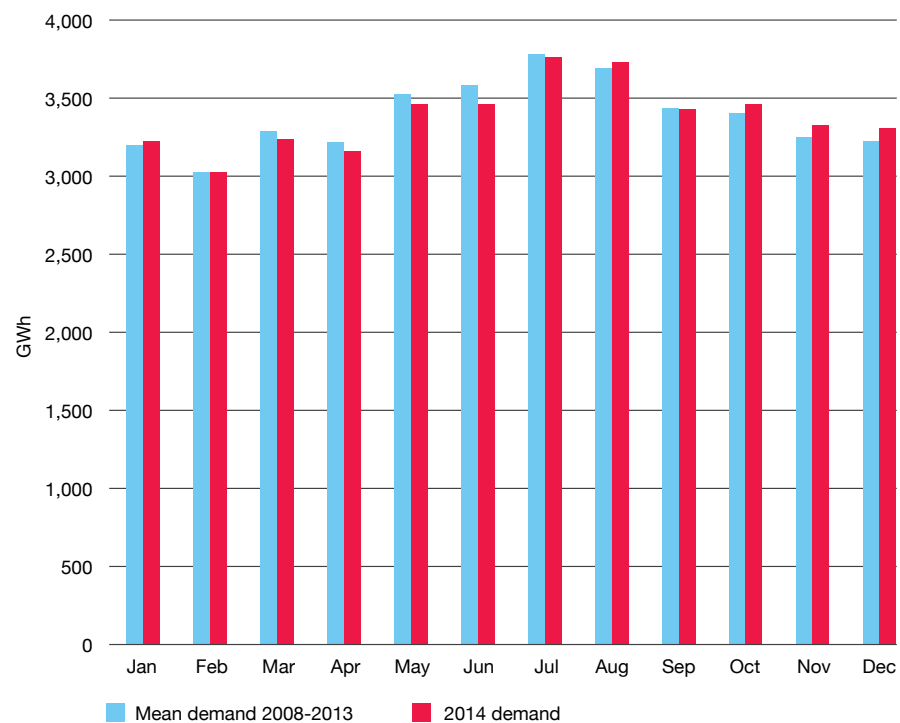


Figure 3 shows total demand in 2014 compared with the previous six years.



PEAK DEMAND

Peak demand drives many of the costs in the electricity network, particularly in transmission and distribution, but it also drives the need for generating plant that can operate for short time periods at high output.

Figure 4: Peak demand

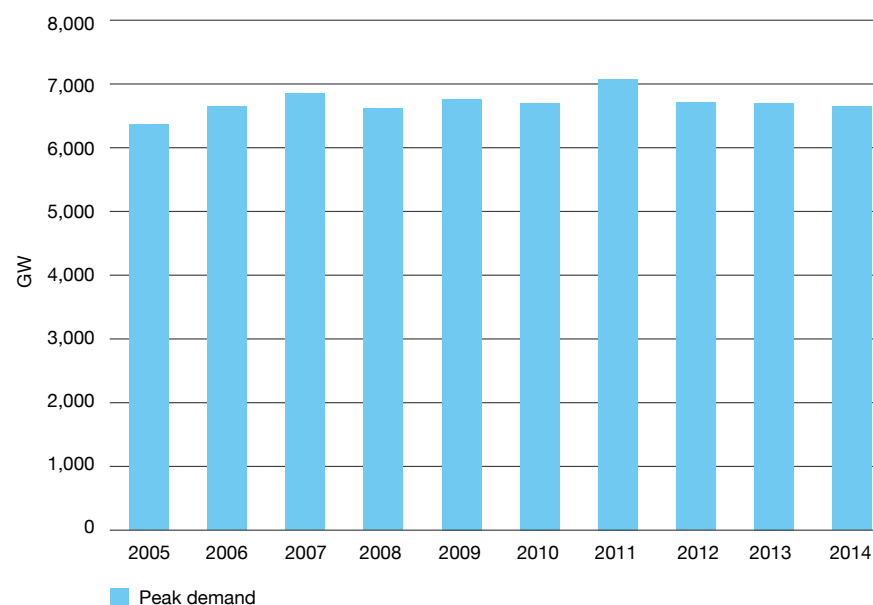


Figure 4 shows peak demand (ie, highest half-hourly demand) for each year since 2005. It shows that peak consumption has remained relatively flat since 2007. The very high peak in 2011 occurred on 15 August during a widespread snowstorm. Note that the units are GW, not GWh.

WE TESTED WHETHER CONTINUED FLAT DEMAND INDICATED A STRUCTURAL SHIFT

Flat demand since 2008 has led to some speculation that there has been a structural break in the economy that has uncoupled growth and electricity use.

A structural break could mean that, at some point in time, changes to gross domestic product (GDP) start to affect electricity demand differently than they had previously.

We wanted to test whether a structural shift had taken place. We developed a detailed demand model to test whether this was the case. The technical detail of the model is outlined on the following page.





Demand model

We developed the demand model to test the nature of the relationship between electricity use and the rest of the economy.

Modelling approach

The modelling used an error correction model and the following set of variables:

- demand for electricity
- price of electricity
- real GDP
- price of natural gas
- population
- the share of electricity use in the household budget
- temperature.

The sources of this data are set out in *table 1*.

Table 1: Data sources

Variable	Description
Demand	Quarterly data from Q1 2000 through to Q3 2013 in GWh. This is the sum of total demand including demand at Tiwai
Price	The QSDEP ¹ series from the Ministry of Business, Innovation and Employment (MBIE) in cents per kWh
GDP	Real GDP series, Statistics New Zealand
Population	Population series, Statistics New Zealand
Natural gas price	Energy Data File, MBIE
Budget share	Cost calculated for an average consumer then divided by average income
Temperature	Nationwide average temperature from NIWA's ² website

Ideally we would also include a variable that measured the effect of changing technology, but we were not able to find a robust measure. We use the QSDEP as a price series; however, since it is a residential price, by using it in a model of total demand we assume prices for industrial and commercial consumers are moving in the same way as domestic prices.

The model performed well. R-squared and adjusted R-squared are measures of how much variation in demand is explained by the model. They both range from zero to one. An R-squared of one means all variation in demand is explained by the model, and an R-squared of zero means none of the variation in demand is explained by the model.

The model has an R-squared of 0.997 and adjusted R-squared of 0.990. Within sample forecasting—estimating the model on a truncated sample, then using the results to forecast periods that we have actual data for—produces a good result as shown in figure 5 below. As this is quarterly data, the seasonal pattern is clear.

¹ Quarterly Survey of Domestic Energy Prices

² National Institute of Water and Atmospheric Research



Results and parameter estimates

The purpose of the model was to test for a structural break—in other words to test whether there has been a fundamental shift in the relationships between the factors that drive electricity demand. The relative stability of the model was confirmed by structural break tests.

The testing has shown there is no evidence of a structural break in 2008, around the time when demand for electricity began to flatten.

The coefficients from the model have the expected signs. For example, we expect a higher price to lead to lower demand, so the negative sign on the price variable is expected. Conversely, we expect as wealth increases so does consumption, so the positive sign on GDP is expected. Real GDP and electricity price are the most important variables in explaining the flattening of electricity demand, as is seen from the relative sizes of the coefficients—these can be found in the full report, and a layperson's guide is available at www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2014/.

Figure 5: Fitted and actual values

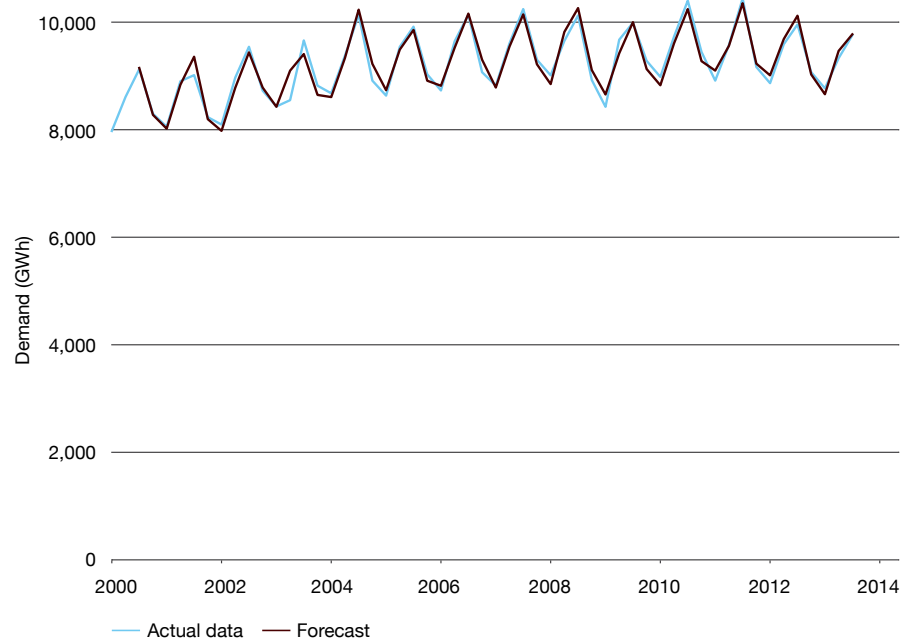


Figure 5 shows the results of within sample forecasting by graphing the model's predictions against actual demand.

RESULTS SHOW NO EVIDENCE OF A STRUCTURAL BREAK

We have not been able to find any evidence of a structural break in electricity demand.

The factors driving electricity demand are those that would be expected. The flat electricity demand since 2008 does not indicate any major change in the structure of electricity demand in New Zealand.

This does not mean there has been no structural change at a higher level. For example, the decrease in GDP generated from the manufacturing sector at the start of the global financial crisis changed the structure of the economy. But the model suggests that its effect on GDP has flowed through to electricity demand the same way as previous changes to GDP have.



SECTION 2: THE RETAIL MARKET



In 2014 the retail market continued the positive trend towards increasing competition across the structure, conduct and performance elements we measure. Particularly notable was the decrease in prices in the competitive part of the sector in the September and December quarters.

WE ASSESS COMPETITION THROUGH STRUCTURE, CONDUCT AND PERFORMANCE

We use a structure, conduct and performance framework to assess competition in markets. Taken in isolation these indicators are limited, but the combination of all three gives an informative assessment of competition levels.

STRUCTURE: THE CONCENTRATION RATIO CONTINUES TO FALL

Market structure is a useful indicator of competition because competition tends to be stronger where there are more players and when no single player has a dominant share of the market. We use the Herfindahl-Hirschman Index (HHI) and the concentration ratio (CRX) to assess trends in market structure. HHI is the sum of squares of the percentage of market shares in a particular market. CRX is the sum of the market shares for X players (for example, CR4 is the sum of market shares for four players).

Figure 6: Residential retail market HHI

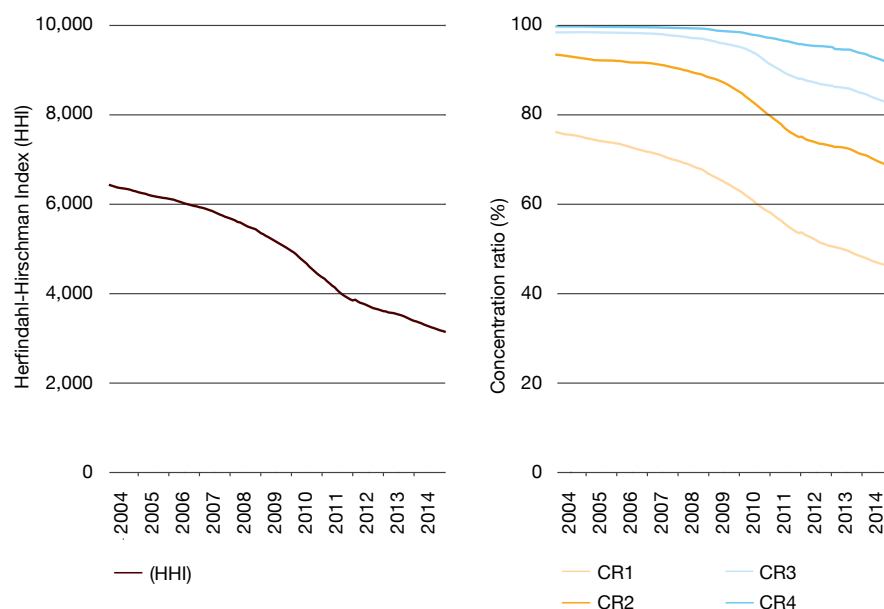


Figure 6 shows the national HHI and CR 1-4 for the residential retail market. Both the HHI and CRX are trending downwards. These are measures of concentration in the retail market, and give information on the structure of the market.

CR1 is the weighted-average of the market shares of the largest retailer on each network. This result shows that the largest dominant player's market share has declined from just under 80 per cent in 2004 to about 50 per cent now. The New Zealand retail market started with what were effectively regional monopolies and has since evolved to a more competitive structure. This change is represented in this result.



STRUCTURE: GROWTH OF SMALL RETAILERS CONTINUES

In 2013 we saw dramatic growth in the market share of small retailers. This continued in 2014. Of particular note is Pulse Energy, which gained around 20,000 customers in steady growth since September 2013.

Figure 7: Pulse Energy's ICP count

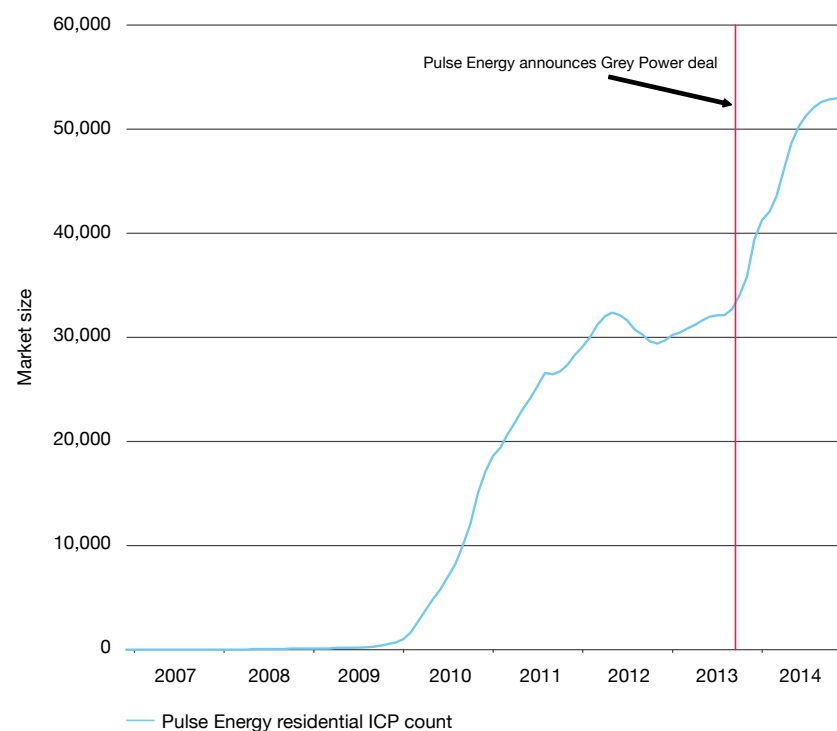


Figure 7 shows Pulse Energy's Installation Control Point (ICP) count. The rapid growth coincides with Pulse Energy agreeing to work with Grey Power to launch Grey Power Electricity and its own Freedom Plan. This is an example of innovation in the retail market where a consumer group and a retailer have clubbed together to form a mutually beneficial arrangement.





CONDUCT: ENQUIRY INTO APRIL 2014 PRICE RISES DISCOVERS CONFLICTING PUBLIC STATEMENTS

We assess conduct by checking for anti-competitive behaviour. Examples of misconduct in the economics literature include any restraints on trade, predatory pricing, price discrimination or non-price abuses of market power.

Electricity retailers and distributors announced price rises in March 2014. The resulting media speculation saw some retailers and distribution companies making conflicting statements about the sources of price increases. This highlighted an area of concern relating to retailer conduct.

The associated media releases issued by some of these parties presented differing estimates of price increases which caused confusion among consumers.

To have an efficient and competitive market, consumers require accurate information. Consumers deserve clear information about the source and size of price increases so they can make informed decisions about their electricity supplier, what fuel source to use for their energy needs and whether to make associated investments, such as insulation.

We conducted an enquiry into the information that consumers received. The most important finding was that consumers can have confidence in the information retailers provide them about price changes.

In all cases, communication between retailers and consumers was transparent. We found no cases where the retailer claimed that the sole source of price increases was transmission and distribution charges or where a retailer increased prices by more than the amount necessary to cover these increases.

Media statements released by the retailers and distribution companies contained conflicting information about the sources and sizes of retail price increases. There were two reasons for this:

- (a) different methodologies used to make calculations
- (b) different subsets of consumers used for calculations.

This issue was illustrated in Wellington. Retailers and the local distribution company (Wellington Electricity Lines Limited) released average price increases to the media that had been calculated differently by each organisation. Wellington Electricity Lines Limited calculated an average retail price increase for its area, which included commercial and industrial customers. The media compared this figure with retail companies' calculations of the average price increases for their residential consumers. To make the calculation, retailers used actual data on the proportion of their consumers' charges that were transmission and distribution related, whereas Wellington Electricity Lines Limited used an average, and then rounded the result.

We remain focused on ensuring that consumers receive accurate and timely information about the source of any price changes.

CONDUCT: CUSTOMER DISCOUNTS AND CREDITS WIDELY OFFERED

In 2014 it was almost universal practice for retailers to offer prompt payment discounts. The standard discounts offered were mostly around 15 per cent, but Energy Online offered 20 per cent and Contact Energy offered 22 per cent for online and on-time payments.

In most cases, prompt payment discounts are essentially a late payment penalty, but with a more marketable name.

In 2014 it was common for retailers to offer residential customers a credit on their electricity bill for joining, which tended to be between \$100 and \$200. Most frequently, \$150 was offered and Genesis Energy's \$300 for a fixed term contract was the most generous. These offers were often accompanied by price freezes or fixed terms, suggesting the retailers recouped the credit through retaining the customer for longer.



CONDUCT: MORE INNOVATION OCCURRING IN RETAIL OFFERS AND MARKETING STRATEGIES

There continues to be an increasing variety in the retail offers available to customers.

Notably, in 2014 Genesis Energy announced it was stopping door-to-door marketing despite it being one of the most popular marketing channels for retailers. According to Genesis Energy's consumer survey, 81 per cent of respondents were not keen on sales people coming to their home.

Flick Electric Co. has been trading since December 2013 and now operates in Auckland, Hamilton, Hawkes Bay and Wellington. Flick Electric Co. passes spot wholesale prices directly on to customers.

Trustpower now offers bundled electricity, gas (LPG or reticulated), phone and internet. It offers price freezes on gas and electricity, discounts for dual-fuel and telecommunications, a free modem and a free broadband connection. These innovations indicate that retailers are seeking new ways to attract customers and achieve a competitive advantage.

Late in 2014 two retailers reduced the amount they pay to consumers with solar panels. This affects the commercial viability of installing solar energy and remaining connected to the grid.

CONDUCT: CUSTOMERS CONTINUE TO SWITCH RETAILERS AS THEY SEEK OUT CHEAPER DEALS

Electricity switching numbers reached a 33-month high in March 2014, with nearly 40,000 account changes taking place. This is the second highest month for switching ever. More than 384,000 consumers switched during 2014.



Switchers are motivated by financial reasons

We surveyed 600 switchers and 600 switchers who cancelled their switch.

We found:

- For those who did switch, financial reasons were the biggest motivator. Results demonstrated 57 per cent of those who switched said they were getting a cheaper deal, and 19 per cent said they were getting a 'better' deal.
- The switching process was generally initiated by a direct approach from a competing company rather than a consumer actively approaching different suppliers about switching. The survey indicates 68 per cent of consumers who switched were approached by a competing retailer. In contrast, only 15 per cent of those who switched took the initiative and approached another retailer for a better deal.
- The survey results showed 53 per cent of those respondents who did switch were approached by their existing supplier who made an attempt to retain them. The most common incentive offered by existing suppliers for potential switchers to not switch was a credit, with 40 per cent of respondents reporting that they were offered a credit. About a third of these respondents reported that they were offered a credit of \$150 or more to stay.
- Once having made the switch, only a small proportion (10 per cent) were willing to make the switch back to their old supplier. The most common reasons for switching back were financial savings, with a third of respondents who returned to their original retailer citing a better deal as the reason.
- Results illustrated 93 per cent of those who cancelled their switches were approached by their existing supplier. About 67 per cent cited financial reasons for cancelling the switch—either their existing supplier made a better offer, or the promised benefits from switching weren't good enough for them to complete the switch.



Figure 8: Saves and switches

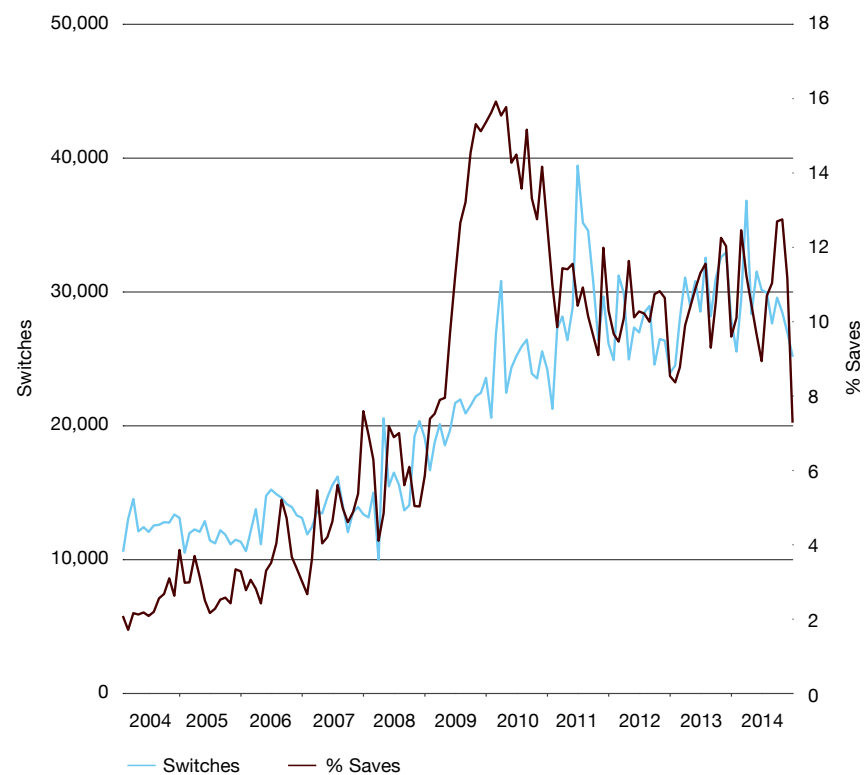


Figure 8 shows the number of residential switches since 2004 and the percentage of initiated switches that are saved. A customer is saved when they cancel a switch that they have initiated. In most cases this happens because their existing retailer makes them a better offer. The percentage of saves peaked in 2009 and has since declined and steadied at around 10 per cent.



PERFORMANCE: A NEW PRICE INDICATOR

MBIE released a new price indicator in 2014, known as the Quarterly Residential Sales-based Electricity Prices (QRSEP). This joins the Quarterly Survey of Domestic Electricity Prices (QSDEP) issued by MBIE and the Statistics New Zealand (SNZ) Consumers Price Index (CPI) series.

The three different methodologies are all attempts to solve the problem around visibility and clarity of average electricity prices that consumers pay. All methodologies attempt to model the prices paid by consumers:

- The QSDEP uses standard plans derived from retailer offers, and assumed consumption to estimate an average retail price in 42 regions. In 2014 MBIE included discounts in the QSDEP, which should improve the measure.
- The QRSEP uses revenue and energy consumption measures from each region to calculate an average price for energy.
- SNZ collects all tariffs offered by retailers in 15 regions. Following this, it calculates effective prices for each tariff based on three hypothetical consumers. This process will always over-estimate the average price paid by consumers, as the 'basket of goods' approach does not account for consumers choosing the lowest rate tariff.

The SNZ series is an index and the QSDEP and the QRSEP are estimates of the retail price in cents per kWh. The QSDEP and the QRSEP are released at different times during the year, and the different methodologies make it difficult to get an overall sense of what the various price indicators are saying.



Figure 9: Changes to the QSDEP



Figure 9 shows sources of change to the QSDEP by year by component. It shows that recently the energy portion is causing less growth than it has in previous years, while transmission is causing more growth than in previous years. Distribution has contributed significantly to increases in most years since 2004.



Figure 10: The QSDEP components through time

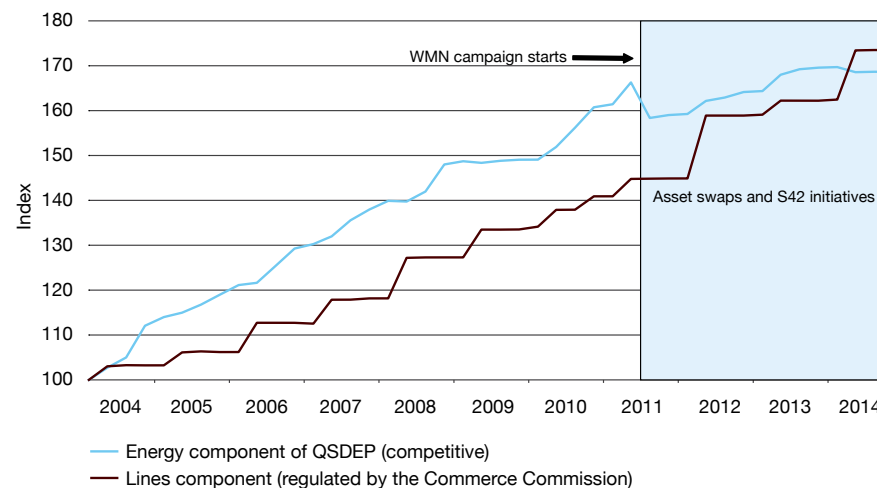


Figure 10 shows the QSDEP components through time as indices. An index is useful for looking at rates of change. The flattening of the rate of increase in energy since mid-2011 is clear from the chart. This is another way to view the fact that the competitive part of the retail price is not the main reason for price increases. Also clear is the effect of the increased lines (transmission and distribution) charges that has resulted from the significant transmission grid upgrade that has recently been completed.

Figure 10 also shows when significant projects aimed at increasing retail market competitiveness were initiated. *What's My Number* (WMN) is a marketing campaign aimed at encouraging people to switch suppliers. Section 42 initiatives included asset and virtual asset swaps, the customer compensation scheme, hedge market development and standardised use of system agreements. These were progressively introduced during 2011. The section 42 initiatives were all large changes in the regulatory and commercial environment that aimed to increase competition in the retail and wholesale markets, and when so many changes are made it is difficult to attribute improvements to any one of them.



Figure 11: Sources of the QSDEP growth

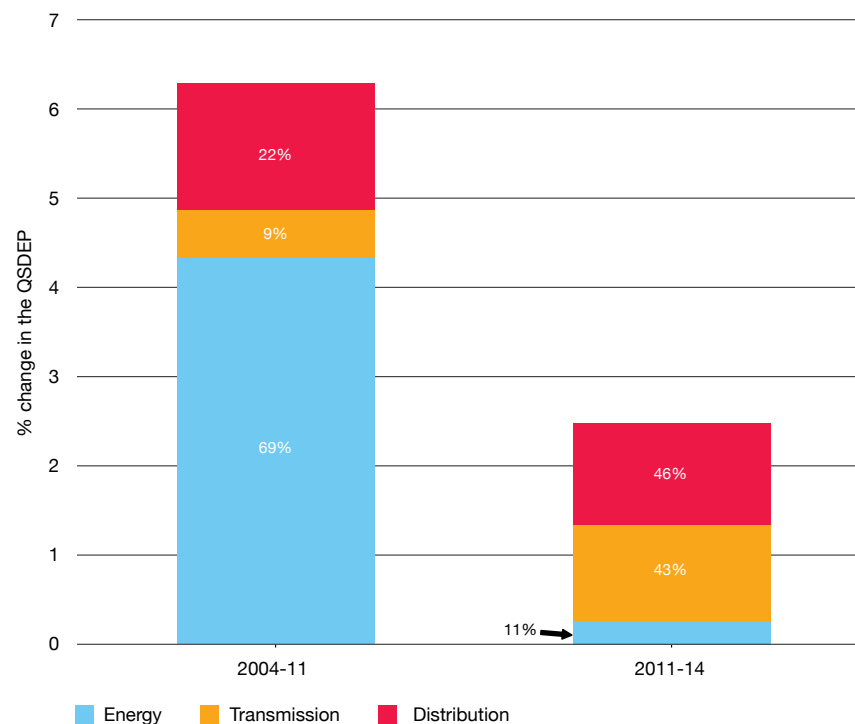


Figure 11 compares the QSDEP components before and after the WMN campaign started in May 2011. It shows the annual growth rates for these two periods (shown by the vertical height of each shaded area). The percentage contribution of each component is indicated by the percentage figures printed in the shaded areas. The chart makes it clear that the competitive part of the market (ie, the energy component) has contributed very little to total price changes since the WMN campaign was launched around mid-2011.





Figure 12: QRSEP components by quarter



Figure 12 shows the components of the new QRSEP by quarter. As the QRSEP is new, there are only five data points. Figure 12 illustrates the changes between these five data points. There is a seasonal pattern in the data due to the seasonality in demand and the daily charge that forms part of most retail tariffs. In the winter quarters, this daily charge is spread over a greater volume of electricity, suggesting a fall in price. Conversely, in the summer, lower consumption suggests a price increase. This explains why the December and March quarters show an increase, while the June and September quarters show a decrease.

**Factors used in cost index**

NZIER has indexed the estimate of costs to make comparisons in the growth rates of costs and prices easier. If costs are growing faster than prices, then this suggests competition is driving down prices relative to costs—prices may still be rising, but more slowly than costs due to competitive pressure. This information is generated using ASX hedge data, demand data, annual reports from the major energy retailers, and regulated transmission and distribution charges.

PERFORMANCE: INDEX SHOWS COSTS CONTINUE TO RISE FASTER THAN PRICES

In a competitive market we would expect prices to be set at or near costs. To assess how well the market is performing we would ideally want to compare costs and prices. Unfortunately, the costs are not easy to determine. To understand how this issue is tracking we asked the New Zealand Institute of Economic Research (NZIER) to calculate a cost index that uses observable market data to estimate costs.





Figure 13: Movements in two price indicators and the NZIER cost index

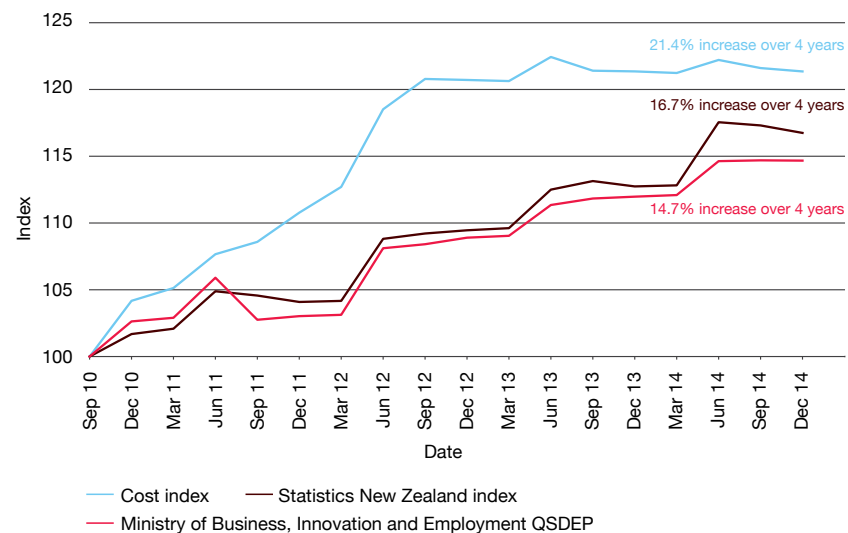


Figure 13 shows that, since the end of 2010, prices have increased more slowly than costs. This suggests there is competitive pressure in the market which is limiting price rises despite increasing costs.



Figure 14: Breakdown of cost increases for NZIER index

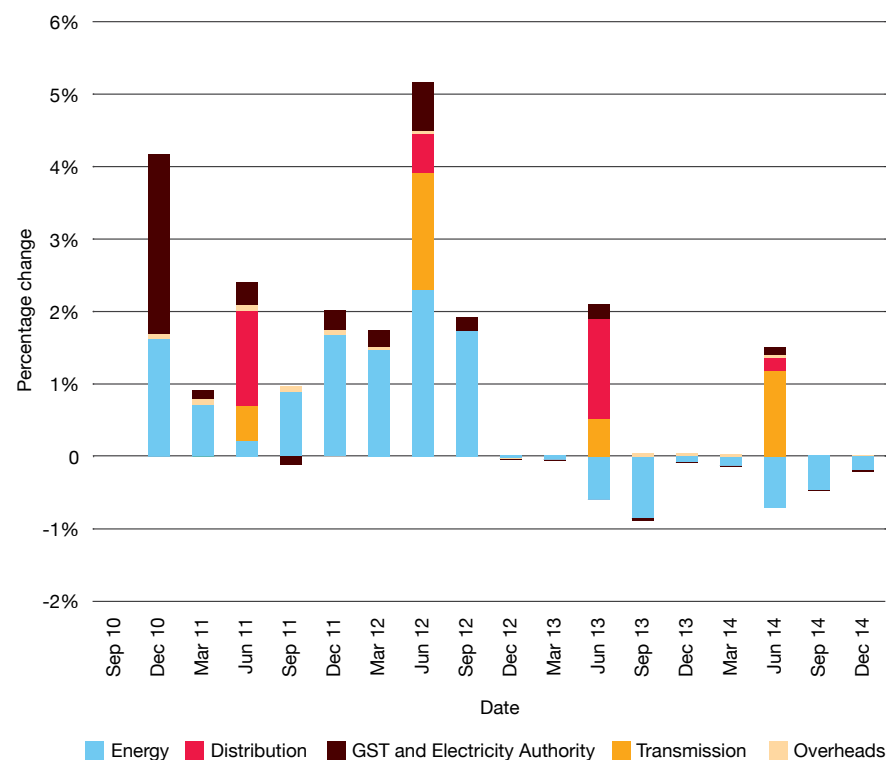


Figure 14 shows a breakdown in the sources of cost increases. The June quarter featured an increase in transmission that was very large, and partly offset by a decline in energy costs. This has been the pattern since the end of 2012 with increases coming from transmission and distribution costs, and energy being consistently low.

This is encouraging as it suggests the competitive part of the market is working well. Energy is traded in a market, so low or decreasing energy costs suggest the market is performing well. The transmission and distribution components of the index are regulated by the Commerce Commission. The main driver of increases in the regulated portion of the index has been large investments in the transmission network, and increases in distribution charges because of a higher weighted average cost of capital.





PERFORMANCE: MORE THAN HALF OF NEW ZEALAND'S METERS ARE NOW SMART METERS

More than half of New Zealand's two million electricity meters have already been replaced with smart meters, and the supply of another 499,000 smart meters has been contracted.

Figure 15: Advanced Metering Infrastructure ownership

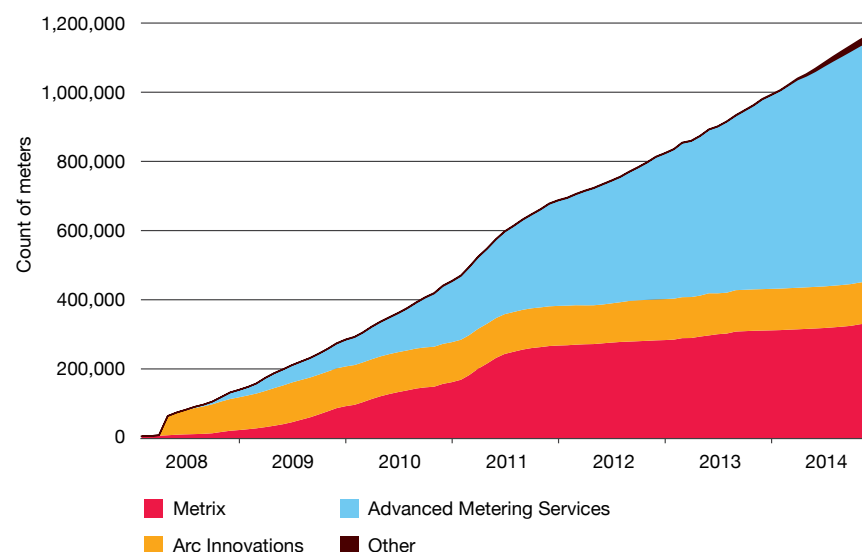


Figure 15 shows the count of smart meters by the suppliers since 2008. Most of the units were provided by three suppliers: Metrix, Arc Innovations and Advanced Metering Services. Meter equipment providers (MEPs) offer services including meter reading, meter data management, remote disconnection/reconnection, load control, pre-pay functionality and smart-grid services to network companies.

Trustpower recently contracted with Mighty River Power's metering business, Metrix, as its preferred supplier through a tender process. Metrix is the biggest meter provider in Auckland and the country's second-largest provider after Vector's AMS business. Meridian Energy's 130,000 meters are provided by their Arc Innovations business.

In late November 2014, the Commerce Commission approved the purchase of Arc Innovations by Advanced Metering Services (AMS). This transaction will increase the market share of AMS, but because Arc hadn't actively expanded since its initial rollout of meters for Meridian Energy, the Commerce Commission decided the transaction wouldn't substantially lessen competition.



SECTION 3: THE WHOLESALE MARKET





2014 was another good year for the wholesale market, and in particular, the hedge market which reached new levels for the third year in a row. In 2014 a focus was a review of multiple frequency keeping in the North Island to help inform further development of this area.

HEDGE MARKET ACTIVITY INCREASES

In 2014 the hedge market experienced increased activity in ASX traded hedges and over-the-counter options, while fixed price contracts and over-the-counter Contracts for Differences (CFDs) fell. Over-the-counter CFDs have been falling for some years, while fixed price contracts showed strong growth in 2013. This could be due to these contracts being for multiple years, meaning that demand in 2014 is covered by contracts entered into in 2013.

Hedges are important as they help manage spot market risk, increase competition in the spot market, provide a robust forecast price for investors and facilitate entry for new retailers and generators.

Figure 16: Hedge products

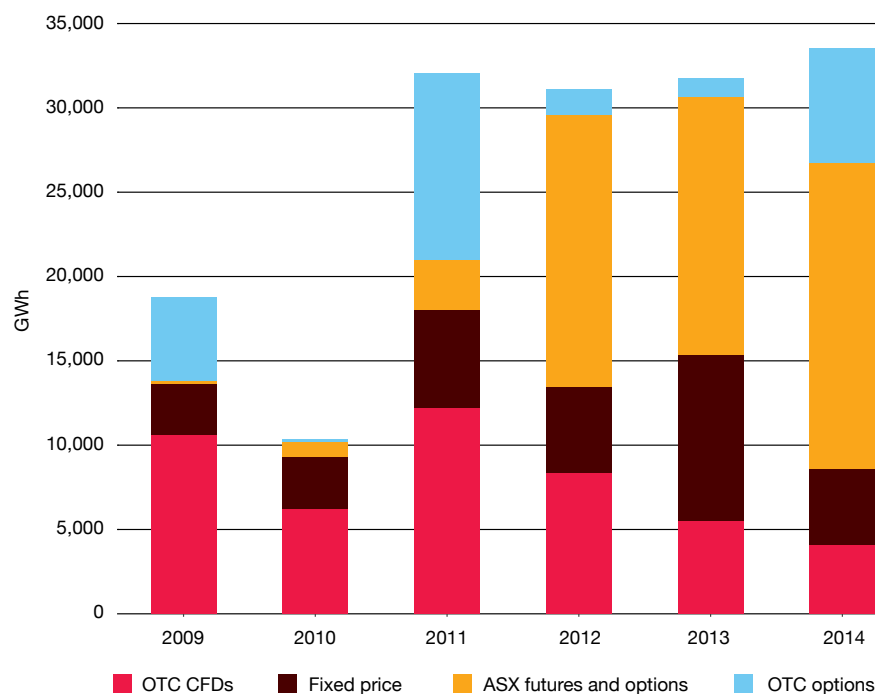


Figure 16 shows four products traded in the hedge market, with the volume of those contracts measured in GWh. The changes in the type and quantity of hedge instruments shown in the chart reflect the preferences of market participants. Overall it is positive for the market to have a variety of hedge instruments available so that participants can choose the most appropriate instrument for the prevailing market conditions.



Figure 17: Trading volumes for ASX quarterly contracts

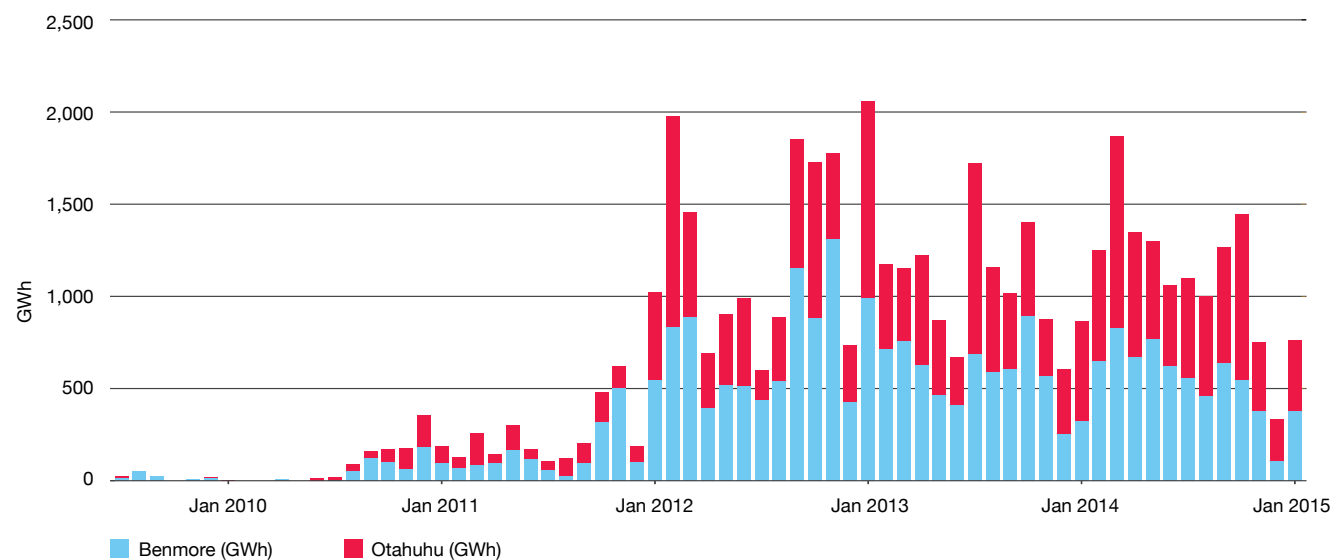


Figure 17 shows trading volumes on the ASX over the period spanning 2009 through to January 2015. We tend to see an increase in trading volumes when hydro storage is short, which was the case at times during 2014. March was the busiest month of the year in 2014 coinciding with below average hydro storage. Overall volume was similar to 2013.





Figure 18: Uncovered open interest for ASX quarterly contracts

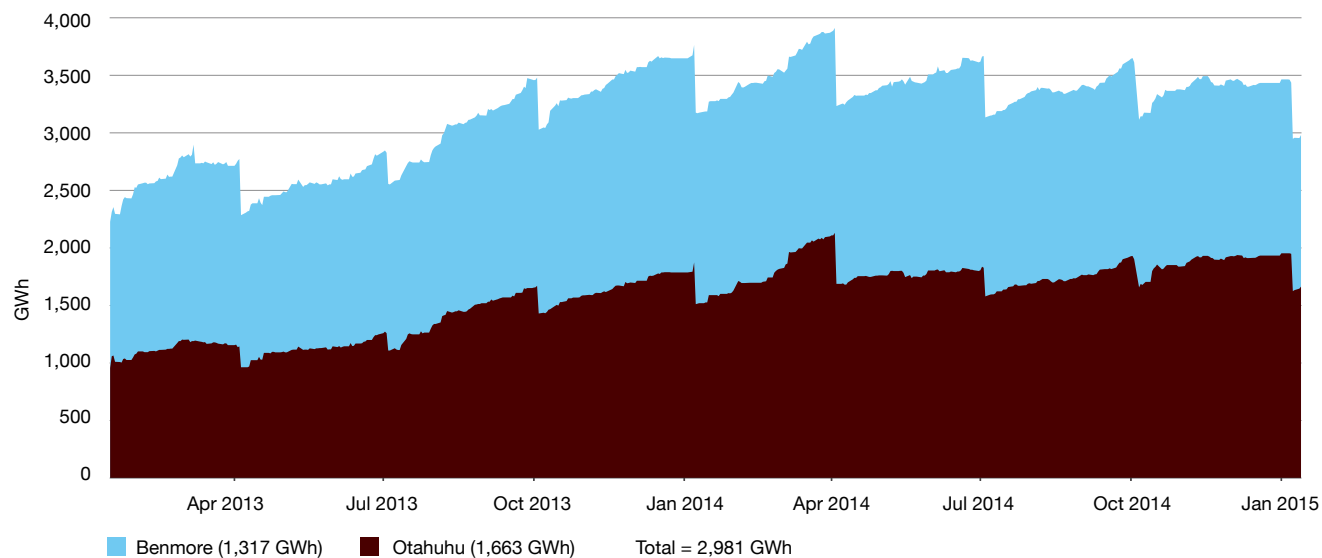


Figure 18 shows the ASX Uncovered Open Interest (UOI) until January 2015. UOI is a measure of the extent that ASX instruments are being used to manage spot price risk and liquidity. Open interest is the sum of all contracts in the market. However, an individual participant in the market can sell and buy contracts that offset each other. UOI is the sum of each individual participant's open interest once this offsetting is accounted for. UOI reached just under 4,000 GWh in April 2014.



THE FORWARD PRICE CURVE IS RELATIVELY STABLE

Figure 19: Forward price curves for ASX quarterly contracts

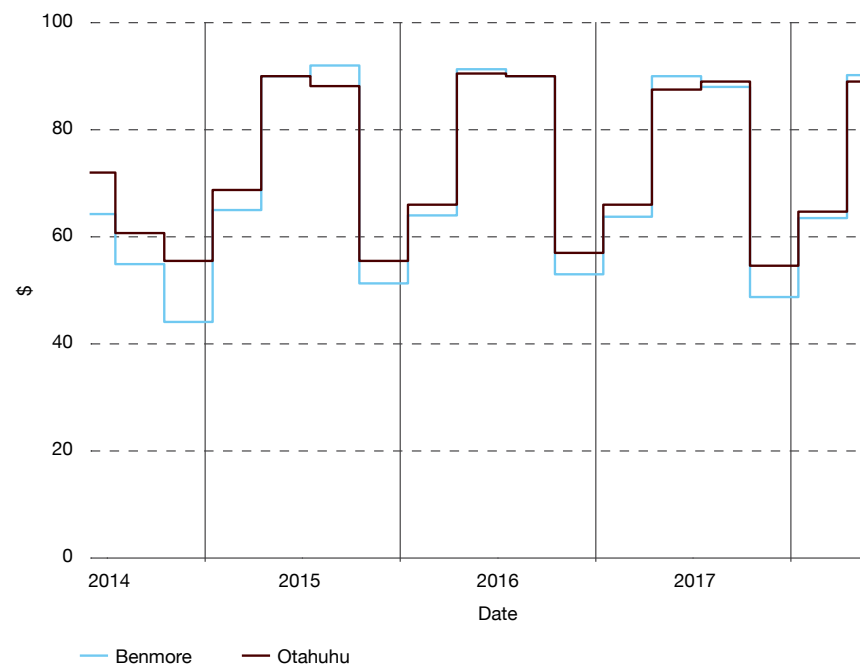


Figure 19 shows the forward price curves for Benmore and Otahuhu as at 30 June 2014. The prices for the June and September 2014 hedges were low compared with previous years' winter hedges, reflecting the abundant hydro storage in the winter and spring of 2014.

The relative stability of the forward price curve for contracts maturing in 2015-2017 illustrated in this diagram is important as it provides a transparent price indicator for any potential investors in the sector, as well as retail entrants.

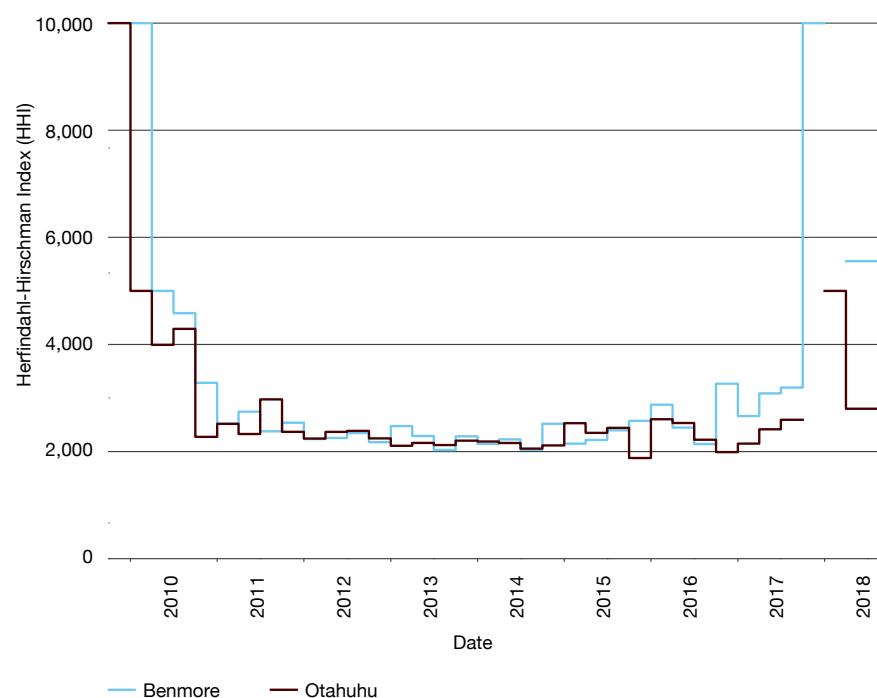




CONCENTRATION IN THE HEDGE MARKET INDICATES GOOD CONDUCT

We also use the HHI to measure concentration in the hedge market. The HHI is usually a snapshot of a particular market, but the hedge market is a separate market for each quarter in the future, so the HHI can be calculated for each of these quarters, as well as for past quarters. As each hedge trade has a buyer and a seller, each of whom is taking a position through the trade, we can calculate the HHI on both sides of the transaction. We monitor this measure because it indicates whether a participant is building a position in the market as this would make the HHI climb. In this case we are monitoring conduct as much as structure.

Figure 20: HHI for buying ASX quarterly contracts



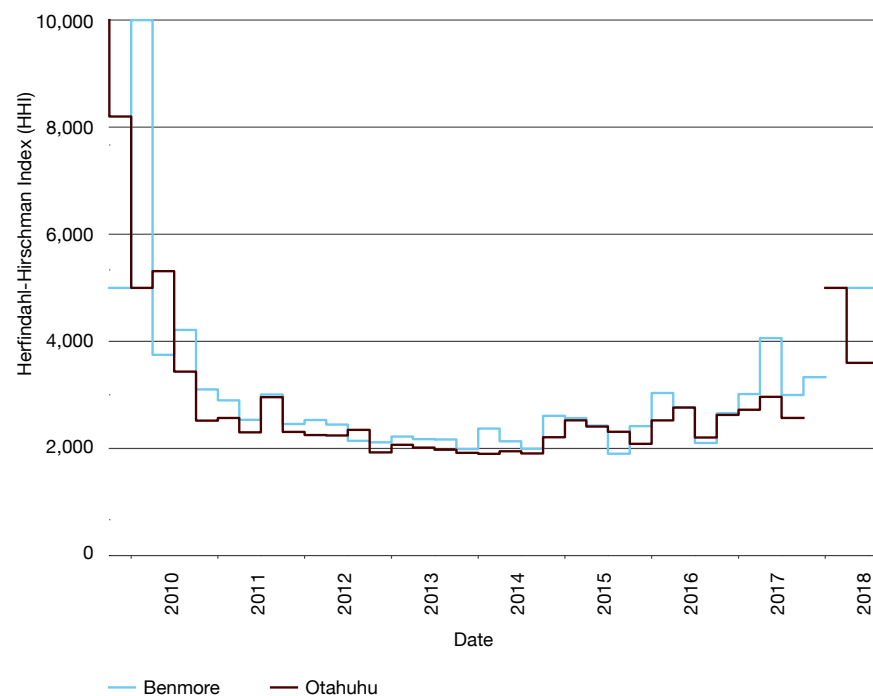
Figures 20 and 21 show the HHI for the ASX for buying and selling as at 31 December 2014. Periods prior to this date are the HHI for the closing positions at the end of the quarter. Periods after 31 December 2014 show the HHI for open positions as at 31 December 2014.

Both charts show that future quarters have high HHIs because volume is very low in those quarters, making it easy for a small number of players to have large market shares leading to high HHIs. In fact there is a quarter in both charts that has an HHI of 10,000 which is the highest HHI possible, and quarters where there is no data indicating that no trades have occurred for these quarters. However, high HHIs in the future do not represent a problem as yet for two reasons. Firstly, the price paid is transparent and any participant can purchase at the price indicated by the forward curve. And secondly, the volumes traded in future quarters tend to be very low so we expect that, as this time period approaches, more contracts will be traded and the HHI will fall.

We expect as the quarters get nearer, the HHI will decline as supply risks such as hydrology become apparent and participants decide on what hedging they require.



Figure 21: HHI for selling ASX quarterly contracts



NEW ASX PRODUCTS HAVE BEEN SUCCESSFULLY INTRODUCED

Late in 2013 several new products were introduced on the ASX.

The new monthly baseload futures, quarterly peak load futures and quarterly options have all been implemented successfully and offer participants more options to hedge their risk.

The monthly baseload futures have been the most heavily traded to date, and open interest has been about 100 MWh (ie, 0.1 GWh) for Benmore and Otahuhu.



NEW NODES INTRODUCED TO THE FINANCIAL TRANSMISSION RIGHTS MARKET

A standard hedge helps reduce price volatility at a single location, and an FTR helps deal with price volatility between two locations. They are designed to reduce the effect of location on competition. They were introduced in 2013 to assist wholesale market participants to manage locational price risks on the national transmission grid and, ultimately, improve retail competition.

FTRs are sold for future months, so each month is a separate market in the sense that parties have a market share for each month.

We are monitoring the HHI for each month so we can identify if participants are building a position in the market—in other words purchasing a large proportion of the available FTRs from the auction. As with the hedge market, the HHI is both a measure of structure and of conduct. The structure of market shares for each month reflects the conduct of the participants—high HHIs suggest that a participant may be building a position in the FTR market. This is especially true as the month in question approaches, but what we tend to observe is that HHIs start high when trading in future months is thin, then fall as the month approaches.

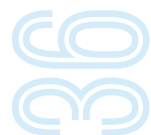




Figure 22: Financial transmission rights HHI for Otahuhu and Benmore

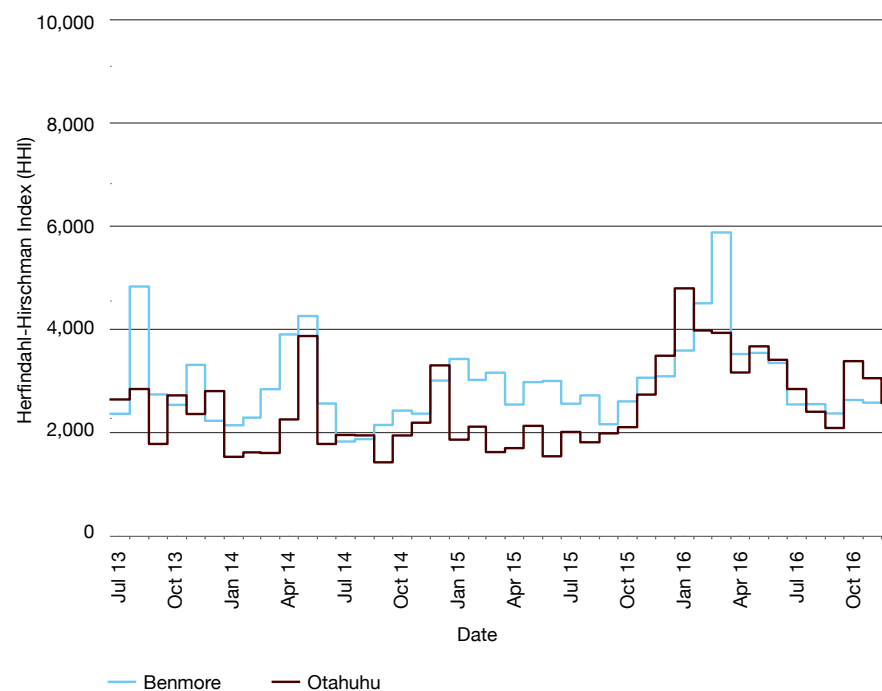


Figure 22 shows the HHI for FTR options for Otahuhu and Benmore. Options make up 97 per cent of the FTR market. These are the HHIs for FTR option holdings for each month since the market started, as at the end of December 2014. The future periods show the HHI as it stood at the end of 2014 for each future month.

The high HHIs in early 2016 are an example of where low volumes lead to high HHIs for future months, and the Authority monitors this as it would be a concern if it persisted as the month approached.

This data excludes the outage at the Penrose substation on 5 October that left as many as 75,000 customers without power.



Figure 23: Financial transmission rights HHI for Haywards, Islington and Invercargill

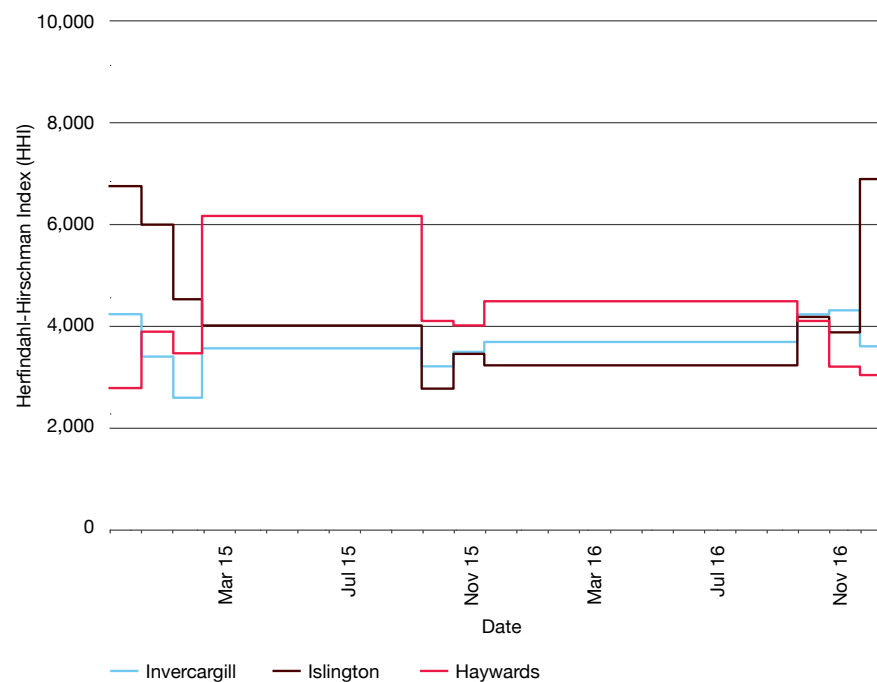


Figure 23 shows the HHIs for the three new FTR nodes implemented in November 2014. The number of nodes increased from two to five with the addition of nodes at Haywards, Islington and Invercargill. The lower volumes for these nodes are the likely cause of the high HHIs and it will be interesting to see how this market evolves.



ANCILLARY SERVICES

Ancillary services are:

- frequency keeping
- instantaneous reserve
- over-frequency reserve
- voltage support
- black start.

Ancillary services are also central to the operation of the power system.

Frequency keeping and instantaneous reserves are traded in markets. Frequency keeping ensures the frequency on the power system stays within prescribed bounds as normal fluctuations in demand and generation occur.

Instantaneous reserves are either extra generation, or load that is willing to reduce, in the event that there is a sudden shortage of energy in the power system. We examine these services below.

Over-frequency reserves are generators that are able to disconnect from the power system if the frequency gets above a certain threshold. This service is contracted between the system operator and generators.

Voltage support is a set of services that ensures the quality of power remains constant. The quality of power can deteriorate due to particular characteristics of the power system, and voltage support corrects this and is procured by the system operator.

Black start is a service to restart the power system in the event of a blackout that forces generators to shut down. This is contracted between the system operator and generators.





TRENDS IN ALL FOUR INSTANTANEOUS RESERVE MARKETS

Figure 24: Reserve market HHI

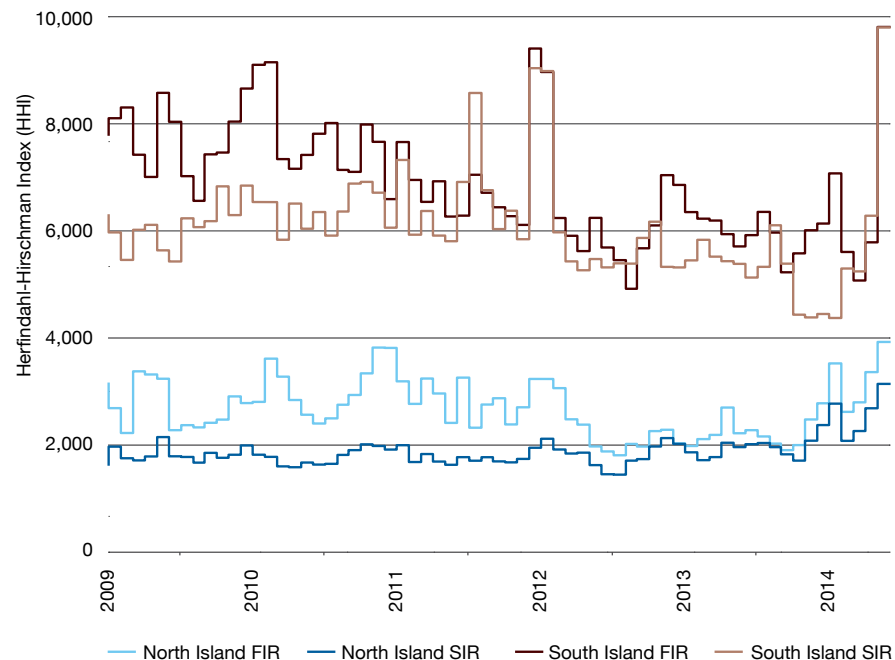


Figure 24 illustrates HHIs for the North and South Islands for fast and sustained instantaneous reserves. This result shows the North Island markets becoming more concentrated during 2014. The South Island remains more concentrated than the North Island. Generators pay for reserves and receive payment for providing reserves, so any imbalance in market shares is a transfer between generators, and they have the option of providing or buying the service.



POST-IMPLEMENTATION REVIEW OF FREQUENCY KEEPING COMPLETED

Frequency keeping refers to the process used to keep the frequency of the grid within its normal band. Frequency keeping power stations are used to increase or decrease generation within a set band to ensure that supply equals demand on a second-by-second basis. Multiple frequency keeping (MFK) was introduced on 1 July 2013 to address a concern that the number of providers able to meet the previous frequency keeping requirements was limited. MFK has been implemented progressively, first in the North Island and then in the South Island.

In 2014 we completed a post-implementation review of MFK in the North Island. This review looked at the frequency measurement, the structure of the frequency keeping market and the cost of frequency keeping for the period July 2012 to July 2014.

IMPACT OF MFK MEASURED

To look at how the frequency changed as a result of MFK being introduced in the North Island, we used data on the frequency from the system operator. The data measured the frequency at 300 milli-second (ms) intervals for the year prior to the switch to MFK, until a year after the switch.

The study tested what had changed when MFK was introduced. Three tests were completed and two of them found a change in the character of the frequency.

The study also looked at the average variance for each 5-minute period. This yielded some interesting results.





Figure 25: Average variance for trading period

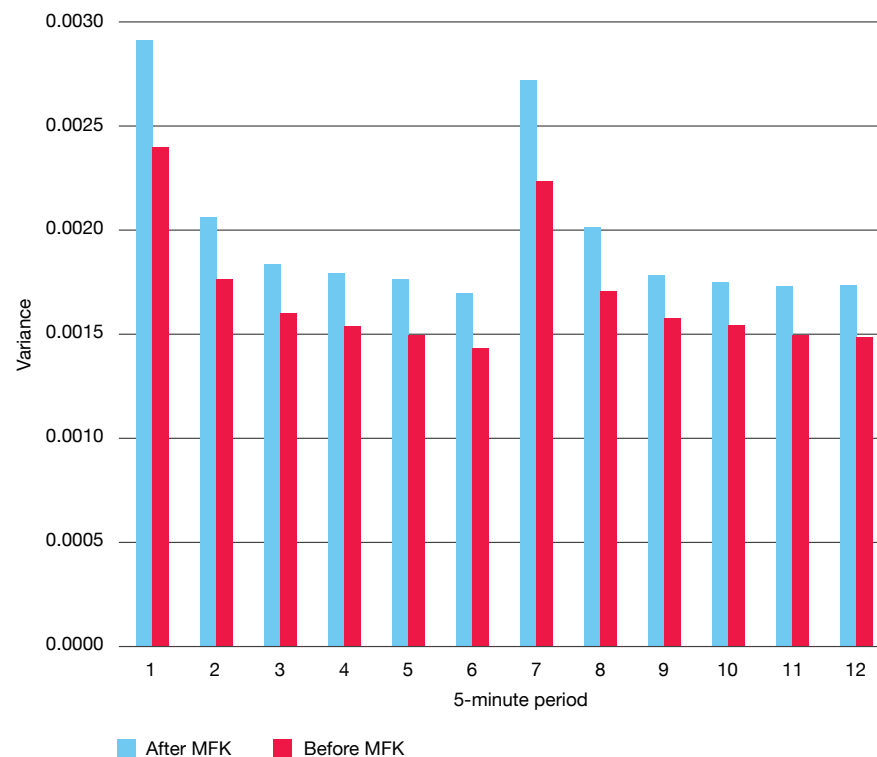


Figure 25 shows the average variances for each 5-minute period in an hour, both of the frequency before and after the change to MFK. The chart shows that the variance declines through each half-hour trading period both before and after the change. This probably reflects the interaction between the frequency keeper for that trading period getting into their band and other generation that is ramping down. Also of note is that this effect is more pronounced during the first trading period of the hour than it is in the second trading period of the hour.

The variance in the frequency also increased after the change to MFK. This is probably due to MFK being organised through a dispatch system. Dispatch takes more time than single frequency keeping when a single station could regulate the frequency. The extra time that dispatch takes allows more time for the frequency to drift before it is corrected.

It is important to note that the change in the characteristic of the frequency is not significant from the perspective of the power system. In other words, while there has been a change, it doesn't matter for the power system.



MFK HAS CHANGED MARKET STRUCTURE A SMALL AMOUNT

We looked at the structure of the frequency keeping market from the perspective of participants, and from the perspective of generating machines used for frequency keeping. MFK should allow participants with smaller plant to enter the market, and existing participants to use smaller plant.

Figure 26: Daily HHI for participants in the frequency keeping market

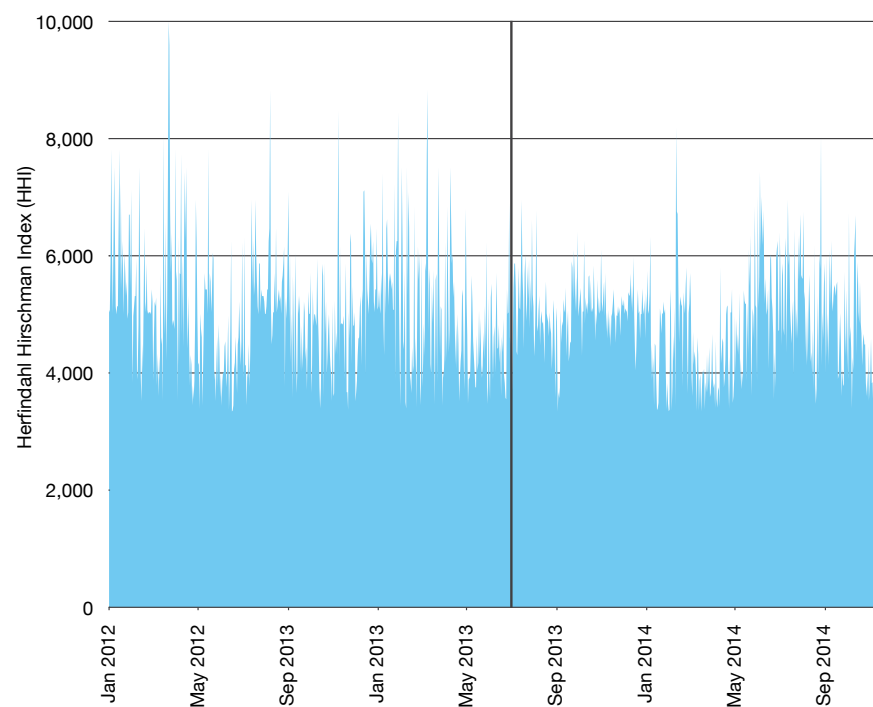


Figure 26 shows the daily HHI for participants in the frequency keeping market. This is calculated using the market shares grouped over each day. The average HHI for the 12 months before the change is 5,009 and after it is 4,857. Although small, the slight decline is statistically significant.

The number of participants hasn't changed over the period with three providers offering this service. The fall in HHI is shown in figure 26 and reflects a more even market share for each of the providers.





Figure 27: HHI for frequency keeping machines

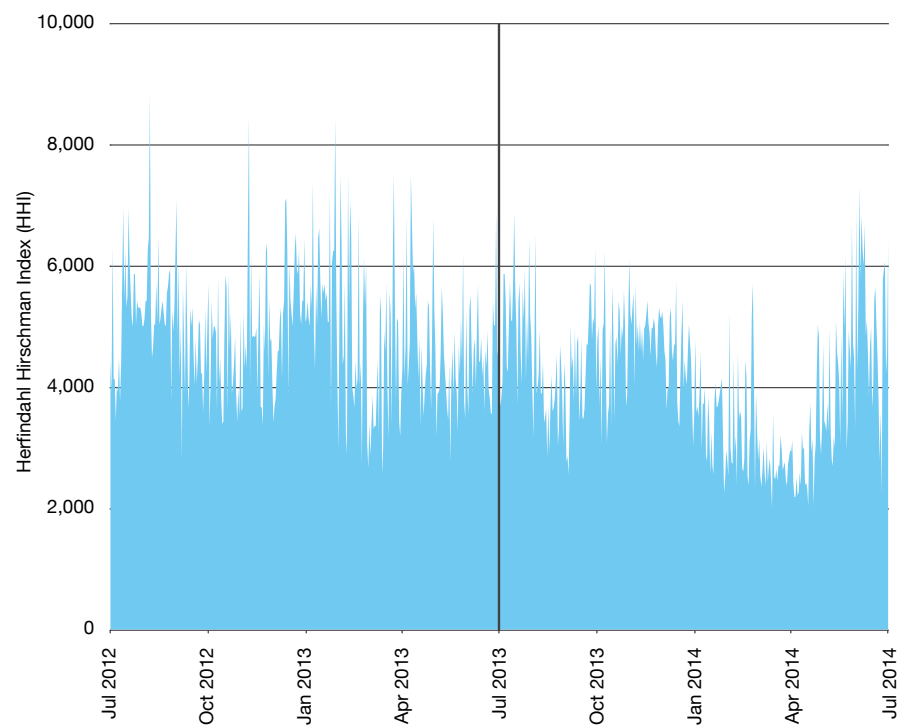


Figure 27 shows the HHI for frequency keeping machines. This is complicated by the fact that in two cases machines are dispatched in groups, so the actual machines used are not visible. The mean HHI before MFK is 4,874, and after MFK it is 4,081. Again, while small, this difference is statistically significant.

The number of machines has increased by one individual machine since MFK was introduced. This is Huntly 5, or e3p, which entered the market because of a change to technical rules needed to implement MFK. As this single entrant is not enough to explain the fall in HHI, the change is most likely due to an evening out of market share rather than the new entry.



MFK HAS NOT SIGNIFICANTLY CHANGED MARKET PERFORMANCE BUT COSTS FALLING

Ideally, MFK would lead to more competition and lower wholesale costs. The daily HHI measure shows that the structure of the market has improved. To assess whether this improved structure has led to lower costs we looked at monthly frequency keeping costs. We scaled these by the monthly demand weighted average spot price to remove the effect of the energy price on frequency keeping costs.

The cost for North Island frequency keeping did fall, but so did costs in the South Island. Therefore, it is difficult to attribute the fall in costs in the North Island to the move to MFK.

We tested the cost data for a structural break in similar ways to the frequency measurement data. There was no evidence to support the hypothesis that there is a structural break. In other words, the data shows no evidence that there were cost reductions from the point where MFK was introduced.

We also tested the average monthly cost of frequency keeping before and after the introduction of MFK to see if they were statistically different. Regardless of whether we used actual costs, or costs scaled by energy price, there is no statistical difference in these means.





Figure 28: Frequency keeping for North and South Islands

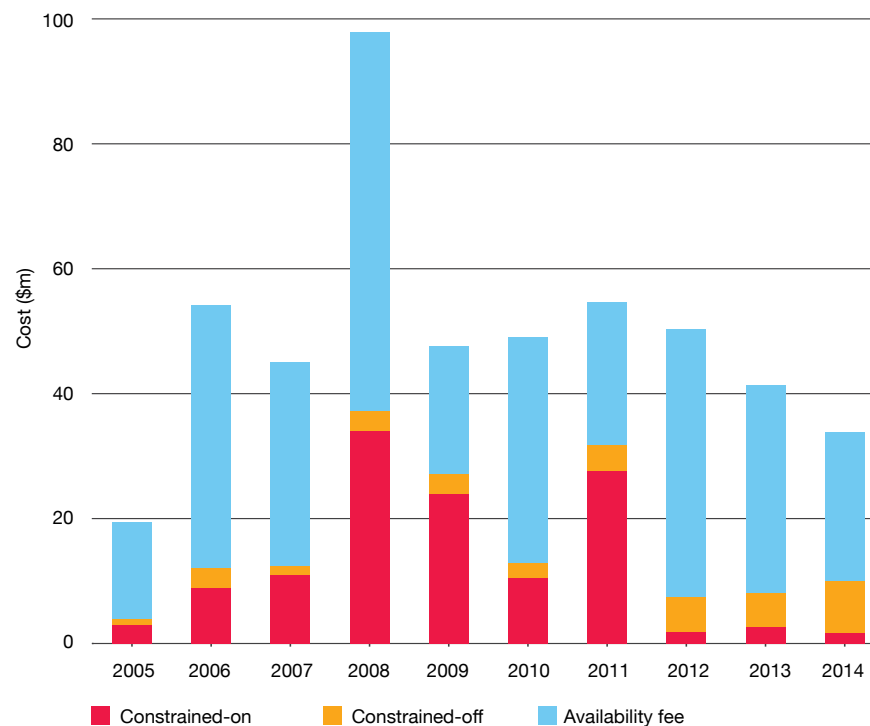


Figure 28 shows the total frequency keeping costs for the North and South Islands. These costs are made up of constrained on and off payments, and an availability fee. Constrained on and off payments are made to generators to compensate them for getting to the middle of their frequency keeping band. Once in the middle of the band they are able to respond in either direction to maintain the frequency at the correct level. The changes to the selection methodology made in late 2011 seemed to have reduced the constrained-on costs, while constrained-off costs have risen slightly.

The conclusion of the study is that MFK hasn't reduced frequency keeping costs in the North Island. However, it is important to note that North Island MFK is a necessary transition to national frequency keeping. National frequency keeping would mean the market is as large and as competitive as possible.

Also it's important to note, as figure 28 shows total frequency keeping costs are falling.



SECTION 4: SUPPLY CONDITIONS AND SPOT MARKET ARRANGEMENTS





2014 was another dry summer, but while storage levels fell, the mechanisms in the spot market and use of HVDC transfers showed how well this situation was managed by generators. Despite the dry summer, hydro generation was actually higher in 2014 than it was in 2013, with thermal generation decreasing during that same period.

STORAGE LEVELS WELL ABOVE 2008 LEVELS

Figure 29: Storage in 2014 compared with 2008

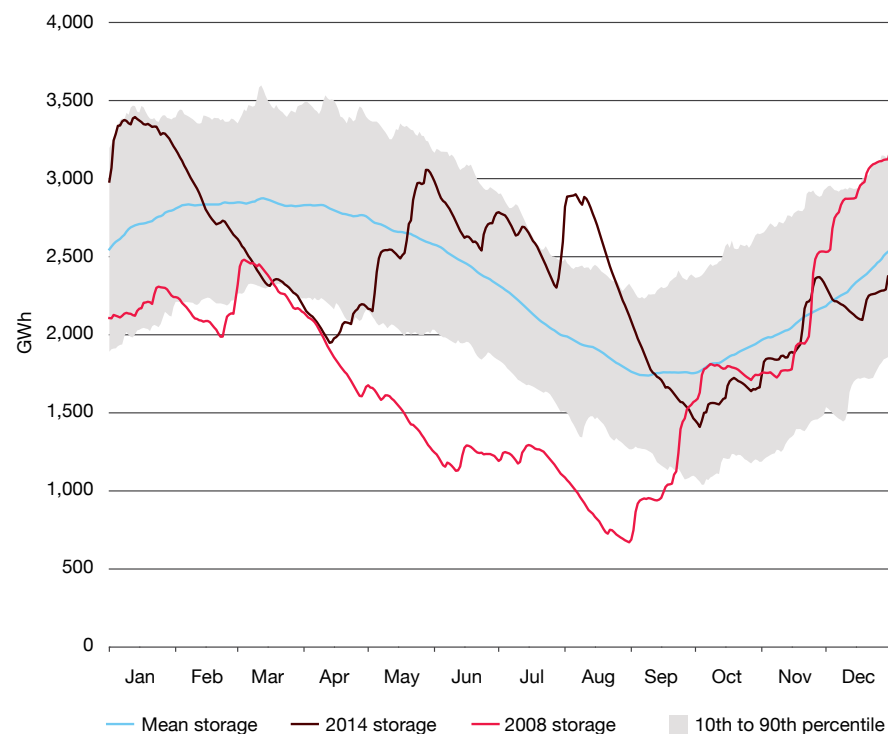


Figure 29 shows 2014 South Island storage, mean storage, and the 10th and 90th percentiles for storage. It also uses 2008 data as a comparison. This figure clearly shows the impact of the summer drought which had storage falling from mid-January until Easter, although, even in this period, storage remained above the 2008 level. The severity of the 2008 winter is clear from this chart when storage kept falling until the beginning of September.



Figure 30: Spot price and South Island storage

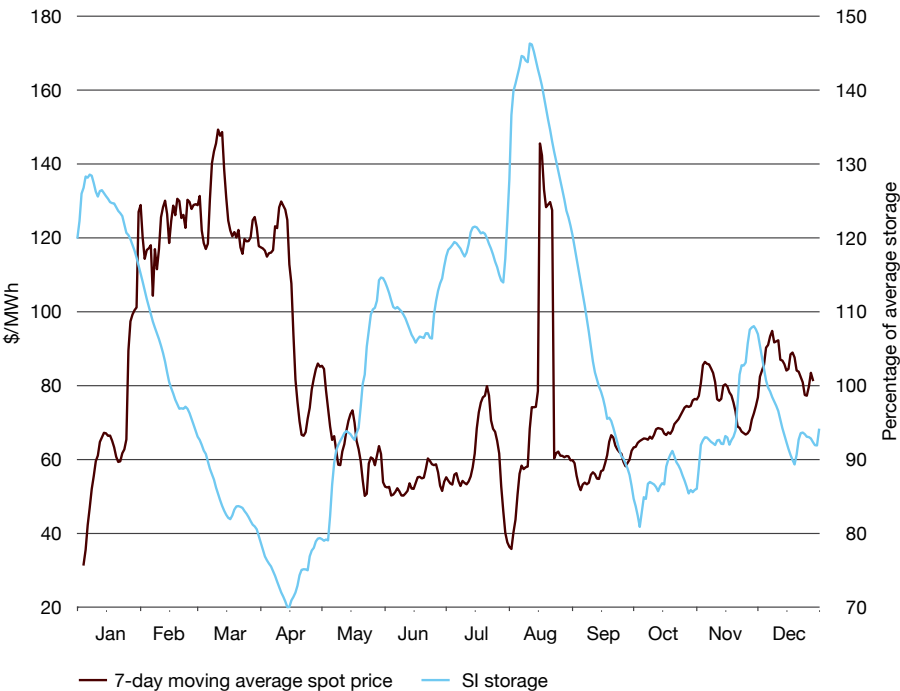


Figure 30 shows the impact of storage levels with spot prices. This figure illustrates South Island hydro storage as a percentage of mean storage and national moving average spot prices. The spot price is inversely related to storage.

Hydro storage experienced a sharp fall in January through to April due to a summer drought. This caused spot prices to increase then stabilise as storage began to increase. The outage of a Maui gas transmission pipeline for three weeks in March coincided with the start of the drought and meant some thermal plant was unable to operate until Maui came back into service.

When storage rose again around Easter, spot prices fell to relatively low levels. The price spike seen in August was partly due to unexpectedly high demand. On 19 August this contributed to very high prices for a half-hour trading period before South Island hydro generation was able to increase its output and cover demand.



Figure 31: South Island storage and thermal generation

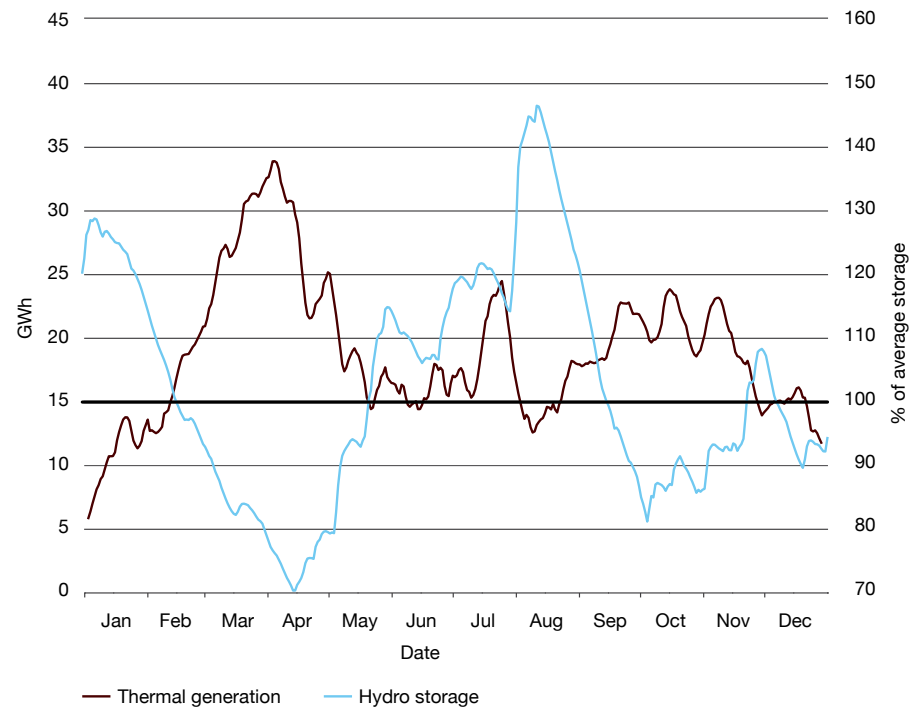


Figure 31 shows thermal generation and South Island storage for 2014 as a percentage of mean storage. As the price rises (as shown in figure 30), thermal generators—which are costly to run—become economic and begin to generate. This increase in thermal output is shown in figure 31 and ultimately reflects the relative scarcity of hydro storage.



Figure 32: HVDC transfers and storage

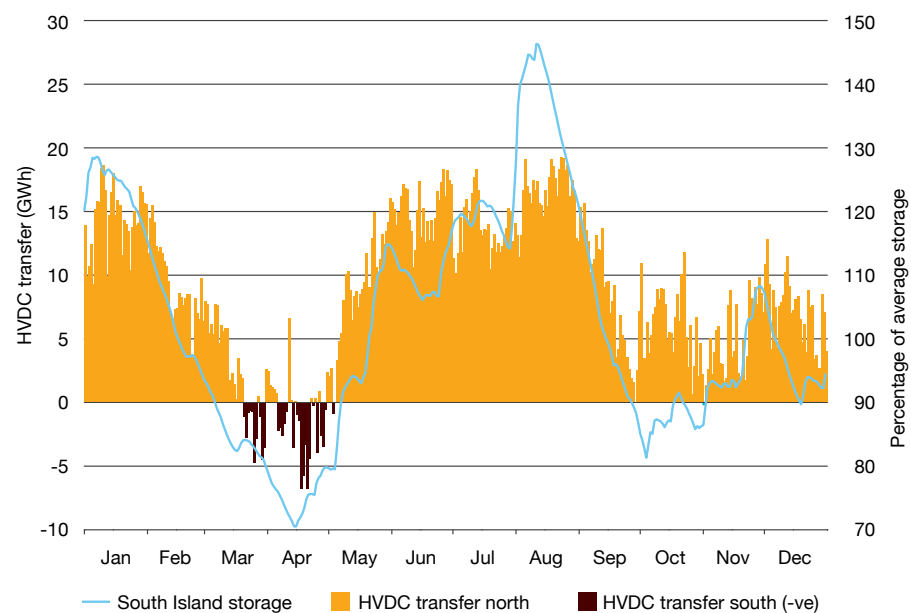


Figure 32 shows transfers over the HVDC line and South Island storage. It shows that when storage in the South Island was low, the HVDC transferred energy southwards. Usually the HVDC runs northwards and between June and August it was doing just that. Later in the year when storage fell to just below average, the level of this northwards flow reduced.

Taken together, these charts show how the electricity market works to increase the security of supply. Prices signal scarcity—in this case, scarcity of hydro storage—and in turn means generators with thermal plant that is costly to operate are dispatched and begin to generate. Because thermal generation is located in the North Island and low hydro storage causes high prices in the South Island, this generally means energy flows southwards on the HVDC.



COMPETITION IN GENERATION HAS INCREASED

Figure 33: Generation by technology

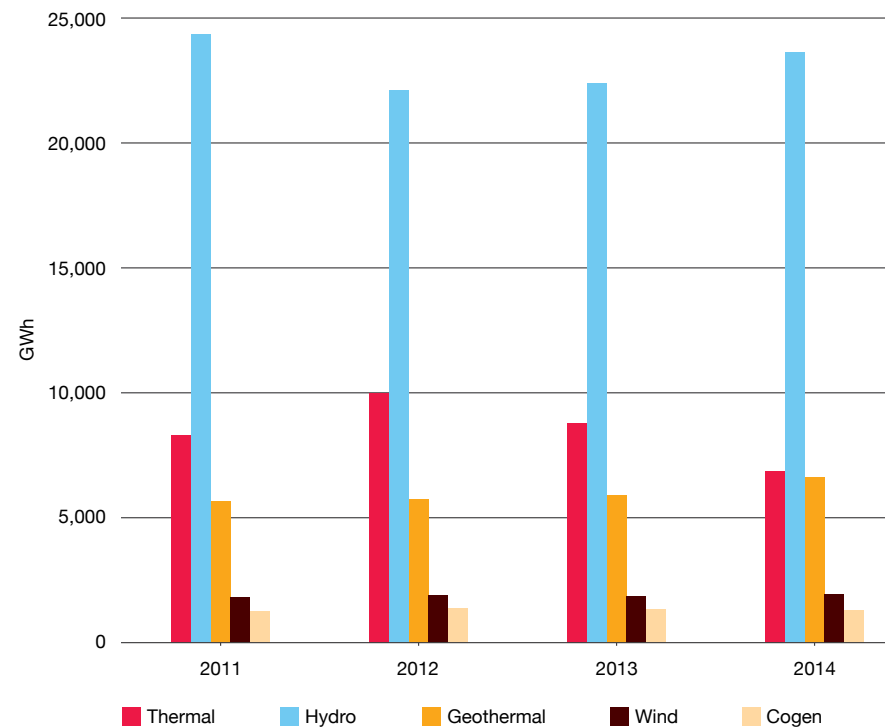


Figure 33 shows generation by technology for 2011 to 2014. Despite the summer drought in the first few months of 2014, hydro generation was higher than in 2013 and 2012, and thermal generation was lower, probably because less thermal was required for seasonal hydro firming. In 2014, 58.5 per cent of electricity was generated by hydro, 17.0 per cent by thermal, 16.4 per cent by geothermal, 4.8 per cent by wind and 3.2 per cent by cogeneration.



Figure 34: Generation HHI

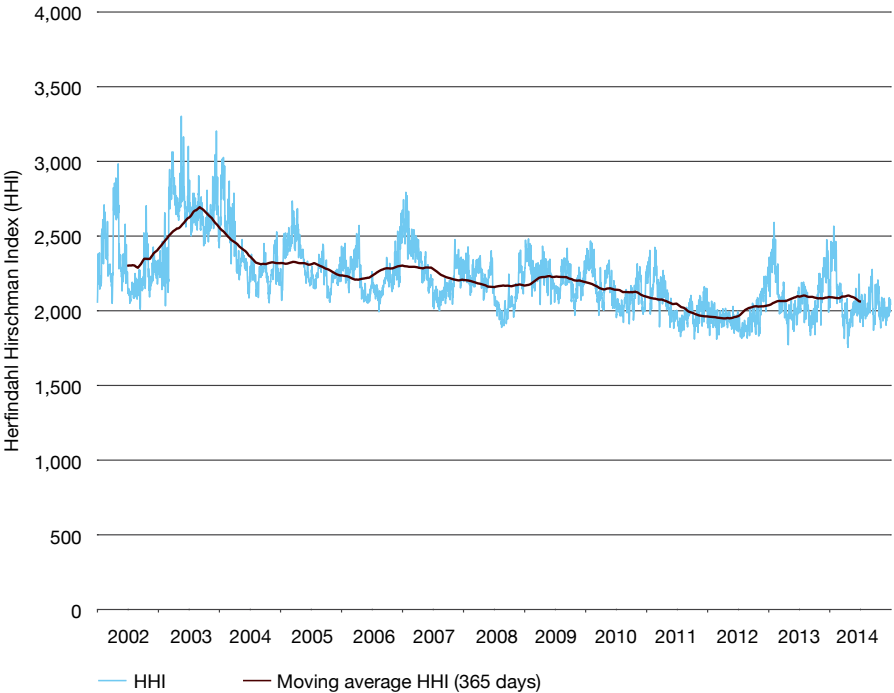


Figure 34 shows the HHI for generation and a 365-day moving average. The HHI for generation is declining over the long term, but it does exhibit seasonality, which relates to hydrology—during times of abundant water, hydro generators have more market share and the HHI increases because ownership of hydro generation is concentrated. The past two years have seen large swings in storage during late summer and autumn; this has had an effect on the HHI with the moving average rising over these years.

It is worth noting that 32 companies sold energy into the wholesale market during this period, and the large generators are also vertically integrated with retail. Coupled with hedge commitments, this means the competitive situation is far better than would be indicated by the HHI alone. These contracted positions and low barriers to entry mean increased competition in the spot market.





WHOLESALE MARKET DYNAMICS CHANGE AS GEOTHERMAL GENERATORS COMMISSIONED

In 2014 we witnessed some interesting dynamics in the wholesale market. In 2013 there were two significant geothermal generators commissioned—Ngatamariki and Te Mihi—which seem to have displaced combined cycle gas turbine (CCGTs) from the market. CCGT generators are able to run in a wide band so tend to generate at low levels when demand is low and at high levels during peak time. CCGT generators also have a relatively high cost due to the fuel they use, and a relatively long start-up time.

What seems to have happened in 2014 is that geothermal generators (which tend to run at a constant output all the time) have made it difficult for CCGT generators to continuously operate profitably. Contact Energy announced in 2013 that the CCGT plant in Stratford would not be offered during the winter of 2014, although it did generate when water was scarce early in 2014. Contact Energy also withdrew Otahuhu B from the market in early August.

Behaviour in the spot market is a function of the rules that govern it. The Authority has a project to review the spot market rules to see if enhancements can be made to further improve hedge and retail market outcomes.

Part of the effect of fewer thermal generators in the market is that the offer curve has become steeper and has a more abrupt transition between low and high priced offers. This means small changes in demand can lead to large changes in price.



Figure 35: Offer curves for trading period 35 on 19 and 26 August

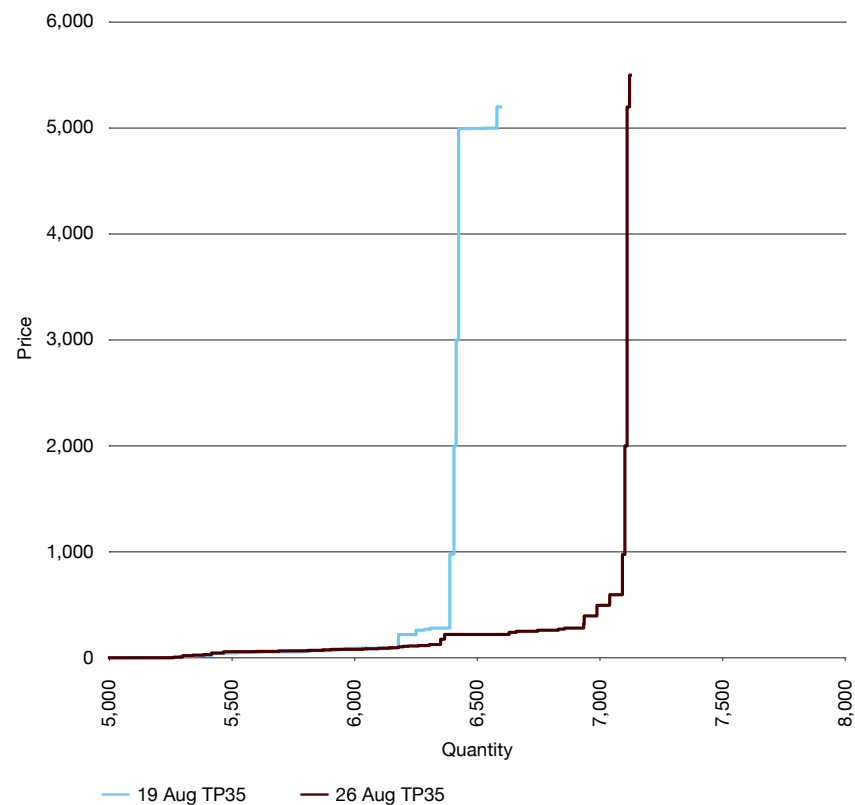


Figure 35 shows two offer curves from August 2014, both for trading period 35. One is for 19 August and the other is for 26 August. The curves differ in both the volume of generation offered and the shape of the offer curve. Clearly, there was far less volume offered on 19 August. This led to a grid emergency and very high prices—\$9,700—over the whole country in trading period 37. The steeper shape of the offer curve is evident visually with far more offers under \$500 on 26 August than 19 August.

To test the idea that there are times when the offer curve has been more sensitive to changes in demand, we used vSPD (vector scheduling and dispatch model) to simulate what market outcomes would be if demand were 2.5 per cent higher each trading period since 2010. vSPD is a model that works in the same way as the model used to dispatch generation in the power system, and is available free from the Authority's website. This involves using the offers that were made in each trading period and simply adding 2.5 per cent to demand and re-solve the market model to see what the change in price would have been.



The results are set out in the charts below. Figures 36 and 37 show the count of trading periods where the difference in price between the final price and the price from the simulation is greater than \$1,000. Figure 36 is the North Island price and figure 37 is the South Island price. The trend in figure 37 is clear, while figure 36 is more difficult to interpret.

The 75 trading periods in 2011 in the North Island represent 0.4 per cent of trading periods that year, so this effect is not common.

Figure 36: Count of trading periods where a 2.5 per cent demand increase caused a price rise in the North Island of greater than \$1,000

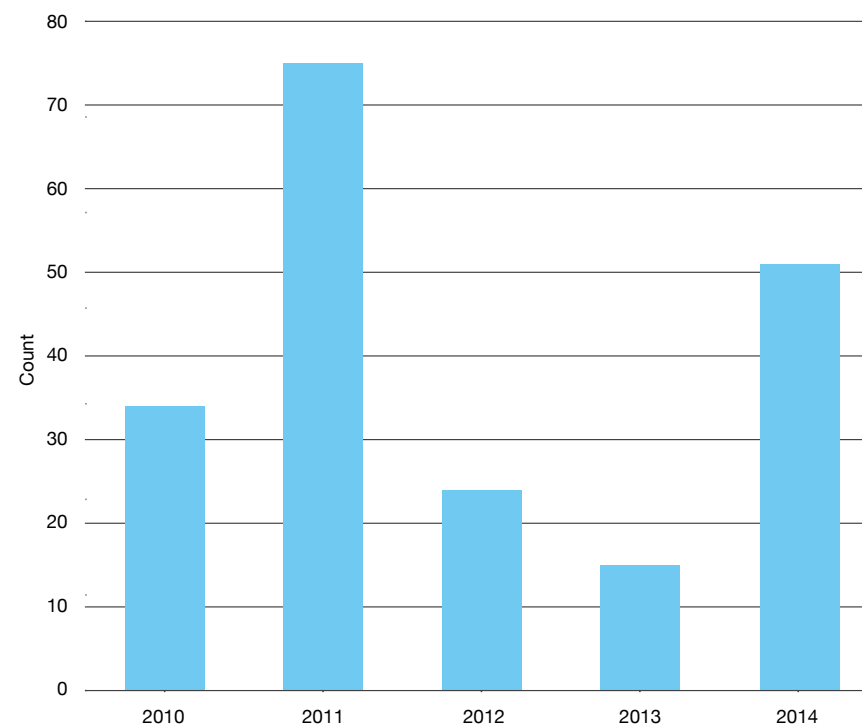


Figure 36 illustrates the count of trading periods—in the North Island—where the difference in price between the final price and the price from the simulation is greater than \$1,000.



Figure 37: Count of trading periods where a 2.5 per cent demand increase caused a price rise in the South Island of greater than \$1,000

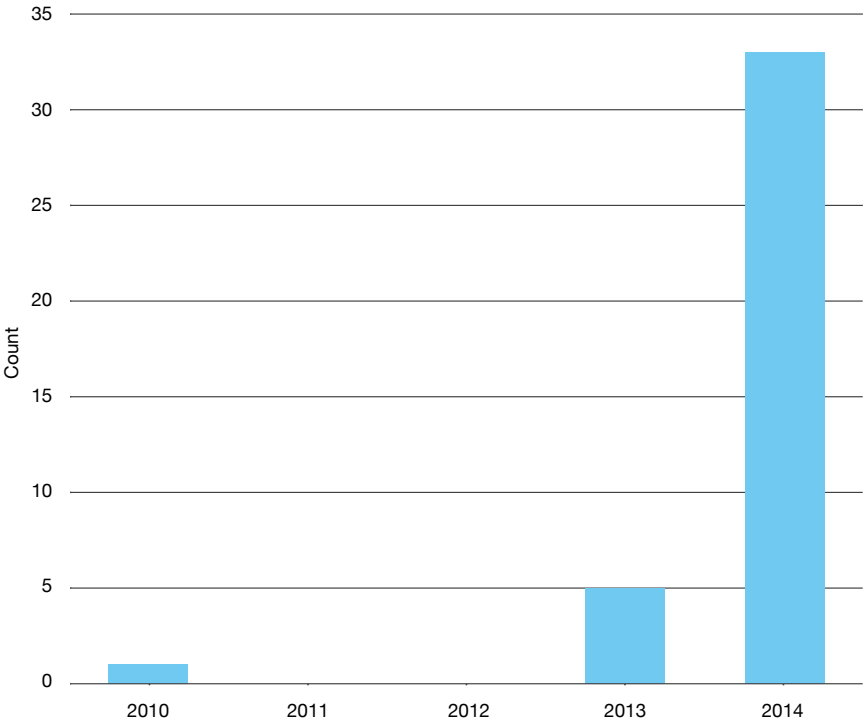


Figure 37 illustrates the count of trading periods—in the South Island—where the difference in price between the final price and the price from the simulation is greater than \$1,000. The trend in the chart is clear.

The simulation that yielded the data in figures 36 and 37 is a more formalised way of saying that the offer curve has a more abrupt transition between low and high price offers.





During the winter of 2014, a number of factors contributed to this:

- (a) a substantial increase in transmission charges over recent years
- (b) large South Island hydro plant on prolonged maintenance over winter 2014
- (c) an increase in HVDC capacity
- (d) an increase in baseload North Island geothermal generation
- (e) above average hydrological conditions pushing energy prices lower over winter 2014
- (f) lower prices resulting in North Island thermal CCGT generators becoming less economic and consequently being pulled from the market
- (g) falling national peak demand (since 2007).

The more abrupt transition between low and high price offers contributed to a grid emergency on 19 August 2014. The Authority released a Market Performance Enquiry into this event. The full report is available at www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2014/.





SAFE HARBOUR MONITORING INTRODUCED TO ASSESS CONDUCT

We are monitoring the safe harbour provisions that were introduced in 2014 as part of new trading conduct provisions, and when we look at unusual prices in the spot market we will look at whether participants are within the safe harbour. The safe harbour provisions are part of trading conduct provisions that prescribe the sorts of behaviours that good conduct entails. They describe a set of conditions which, if met, mean the generator is deemed to be behaving in a way consistent with good trading conduct. Behaviour inconsistent with the safe harbour provisions may also be good conduct, but the generator is no longer protected by the safe harbour provisions and the behaviour may be challenged by other participants.

Prior to the implementation of safe harbour provisions, the Authority set up monthly island-wide monitoring of the provisions. We will look to develop regional automated monitoring over smaller regions in the future. Our monitoring of unusual prices should pick up instances where generators are pivotal and taking advantage of this. In addition, we have discovered that it is not always obvious when generators are pivotal at an island level, so the monitoring adds to our understanding of how the market is operating.

Our monitoring consists of looking for a coincidence of a generator being net pivotal, raising offer prices and a consequent higher market price. The reasoning is that, unless there is an offer change, the generator hasn't carried out an action to take advantage of being net pivotal, and if there is no change in spot market prices, then there has been no effect from being net pivotal.

The net pivotal calculation is achieved by starting with a simulation where, for each large generator in each island, all offer prices for energy and reserves are raised to 30,000. If the generator is dispatched under these circumstances, it is counted as gross pivotal. The generator's obligations are then subtracted from this gross pivotal amount. These obligations are demand (in the form of purchases on the spot market) and sold hedges (including virtual asset swaps). Generators also have opposite positions such as purchased hedges and FTR positions. These are added onto the gross pivotal amount.

If the calculation yields a positive amount, then this is counted as net pivotal.





Figure 38: Net pivotal monitoring: percentage of time net pivotal

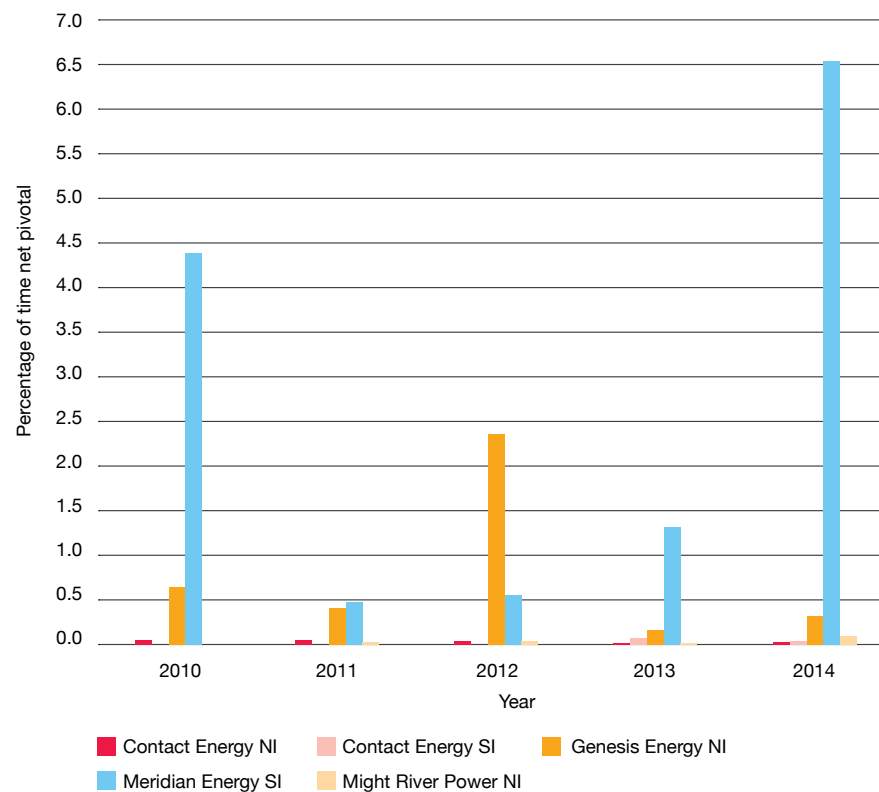


Figure 38 shows the percentage of trading periods where the various traders are net pivotal. It shows that Meridian Energy has become increasingly net pivotal over the last four years after a fall at the end of 2010. We believe the fall between 2010 and 2011 is due to the virtual asset swaps and asset swaps. We believe the increase is due to Meridian Energy having progressively lower South Island winter load, which means it often has a large surplus of generation.



RELIABILITY SHOWS GREAT VARIATION YEAR TO YEAR

Figure 39: Unserved energy due to transmission outages

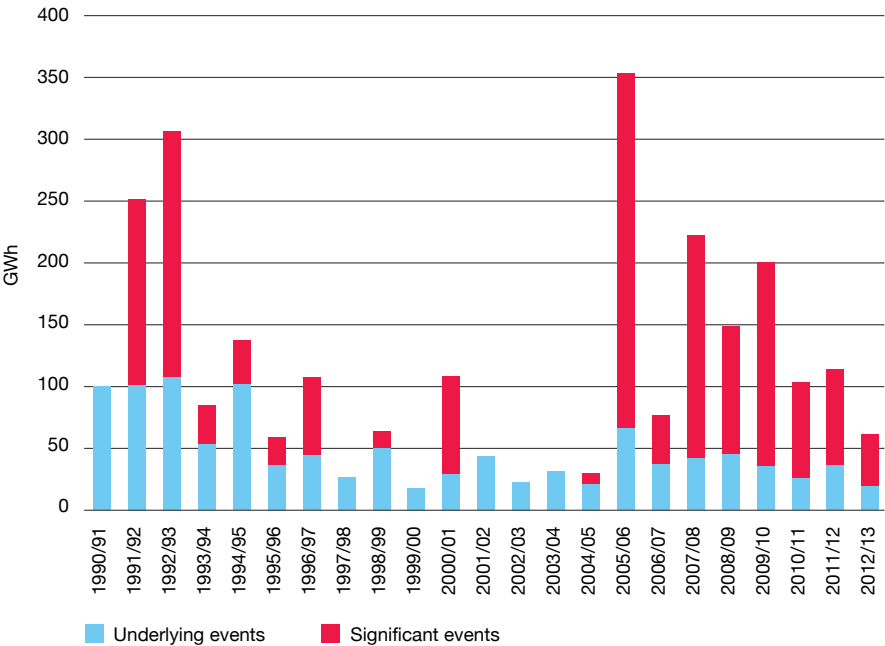


Figure 39 shows outage data taken from Transpower’s Quality Performance Report. The chart splits outages into unserved energy due to underlying events and events that are significant. Transpower defines significant events as events that last more than one system minute and underlying events are those that last less than one system minute. A system minute is energy used during the highest demand period of that particular year. There is great variation year to year and the quality performance report details the reasons for the significant events.



Figure 40: Average distribution company SAIDI

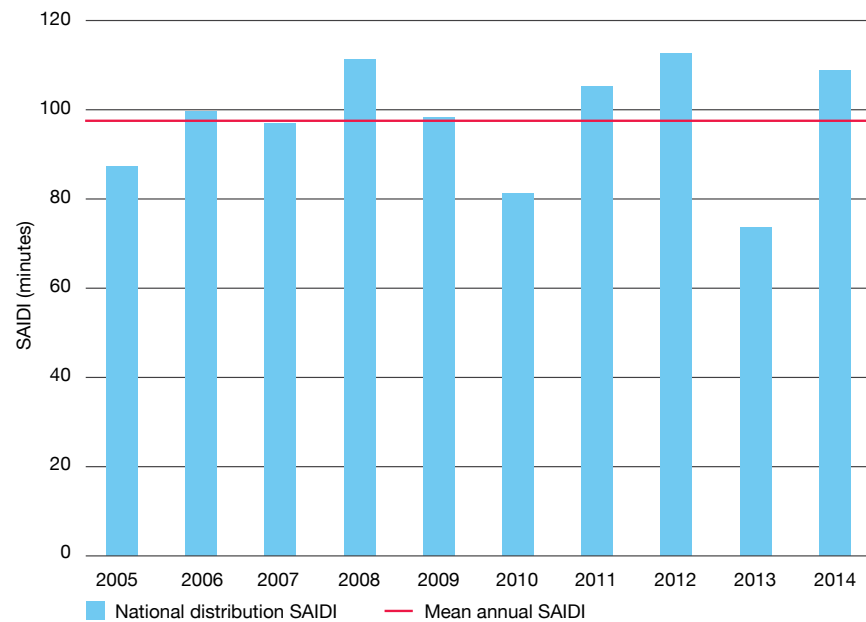


Figure 40 shows outage data from a sample of distribution companies in New Zealand. This data is a different measure of reliability called System Average Interruption Duration Index (SAIDI). SAIDI measures the average number of minutes of outage that customers experienced during a particular period. The Commerce Commission only requires distributors that are not consumer owned to disclose this information; this data is for these 16 distributors.



New Zealand distributors' SAIDI numbers are comparable to overseas jurisdictions. In New South Wales, SAIDI ranges between 5 minutes for CBD areas to over 900 minutes for remote rural areas. Alberta has an average SAIDI of about 105 minutes.

100 per cent reliability is not realistic.

Subsequent to the fire at the Penrose substation in October, which resulted in a large number of Auckland homes and businesses being without power for up to 2 days, there was public comment about the desirability of a network that is 100 per cent reliable. Resilience in a power system generally comes from either duplicated assets, or duplicated ways of supplying different areas. Following the Penrose fire, many homes and the Auckland CBD were able to continue to be supplied because these points could be supplied from multiple sources.

The complicated trade-off with resilience is how much to spend to get a certain level of reliability. Distribution companies spend about \$0.6 billion per year on capital investment. Transpower has spent about \$2.8 billion over the last 4 years on capital investment. This expenditure is recovered from consumers through lines charges, which form part of electricity bills.

Not all of this expenditure will be aimed at improving reliability, but the size of the sums involved indicates that it is important to consider the trade-off between expenditure and resilience carefully.

Transpower's Quality Performance Report contains a list of all significant events since 1987. The causes include lightning, snow, maintenance equipment dropped onto a live bus, a rat, a tree fire, human error, earthquakes, protection design problems and many other reasons. Building a system that is resilient to this range of causes is not possible—100 per cent reliability is probably not achievable at any cost. The objective is to build a system that achieves an efficient level of reliability.

There is probably no way to calculate the 'correct' level of reliability. Ideally, investment would be made to increase reliability up until the point when the extra reliability was worth less to consumers than what it would cost. Like many things in the public sector the approach is to use administrative processes to somehow aggregate the value of reliability.

The Commerce Commission sets minimum service levels for the distributors that it monitors and provides incentives for the distributors to meet them. The Commerce Commission consults widely before setting these standards to understand how much consumers value reliability. This is necessary as different consumers will have different levels of tolerance for reliability and the Commerce Commission necessarily sets an average. These processes attempt to aggregate preferences for reliability and are a way of ensuring the trade-off between cost and reliability is constantly reviewed. The Commerce Commission sets similar targets for Transpower.







SECTION 5: MARKET PERFORMANCE PROJECTS



In 2014 we completed four market enquiries covering issues ranging from retail pricing to grid emergencies. Our enquiry process looks at market and reliability events.

ELECTRICITY CONSUMPTION

Authority staff conducted an enquiry into the causes of the flattening of electricity consumption that we have seen since 2007. This work is summarised on page 9 and is available at www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2014/.

RETAIL PRICE CHECK

Price rises in April resulted in media comment about the causes of the increases and Authority staff undertook an enquiry into the various claims. The enquiry was carried out in two parts. The first part covered the four largest retailers in Auckland, Wellington and Christchurch. It found the letters from retailers were consumers' best source of information about price changes. It also found the media statements contained numbers that were calculated using different methodologies, rounding and other variations, which led to confusion among consumers. The full report is available at www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2014/.

The second part of the enquiry involved smaller retailers in areas across the country and larger retailers in areas not already covered.

WINTER GRID EMERGENCIES

There were two grid emergencies in the winter—one in May and the other in August. The grid emergency in August resulted in very high spot prices. These two events were similar in that they were caused by demand being very close to the limit of supply.

The Authority's market performance enquiry found there was no action that any participant took that was inconsistent with the Code. However, the enquiry did highlight some features of transmission pricing that had an effect on the stability of the power system. This is detailed in the section on grid emergencies and transmission pricing. The full report is available at www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2014/.

FTR RENTALS

As part of its function to monitor the FTR market, the Authority recently enhanced its vSPD FTR rental tool to accommodate three additional FTR hubs, bringing the total number of hubs to five. During the testing phase of this initiative, the simulated results were compared with the actual historical results generated by the FTR manager. These tests revealed the results produced by the vSPD FTR rental tool were different from those published by the FTR manager.

We completed an enquiry, and the FTR manager also investigated (and has agreed with our assessment). The FTR manager has initiated two change requests to correct the discrepancies. The impact of the discrepancies was potentially substantive, although to date, the actual errors in the calculation of FTR rentals have been immaterial.



PROJECTS IN PROGRESS

We also have the following projects underway:

Metering

Authority staff are conducting an enquiry into metering. We are interested in the contractual relationships between retailers and meter service providers, and how pricing varies with these different relationships. We are focusing on whether there are barriers to entry into the retail market that result from arrangements in the metering market. We asked for and have received the pricing schedules for each of the three main metering service providers.

Penrose substation fire

On 5 October 2014 a fire at Penrose substation in Auckland caused a large outage which, at its peak, meant 75,000 people were without power. The Minister of Energy and Resources directed the Authority to undertake an inquiry. This inquiry is in progress.

Multiple frequency keeping

We conducted a review of MFK in the North Island. The results are summarised on page 41.

AUFLS

On 12 November 2013 the first stage of North Island Automatic Under Frequency Load Shedding (AUFLS) was activated, resulting in 401 MW of lost load and activation of fast instantaneous reserves. The AUFLS activation was the result of an HVDC commissioning test of Pole 3 which involved deliberately causing a fault in the AC power system north of Haywards, while the HVDC was running northwards at high power. This caused equipment at Benmore to trip, leading to a rapid decrease in HVDC flow and the AUFLS being activated in the North Island. The Authority initiated an investigation to consider issues relating and contributing to the 12 November 2013 AUFLS activation event.

Saves and win-backs

Authority staff analysed survey data on saves and win-backs using a statistical model. The study found that the presence of teenagers, household annual income above \$100,000, household electricity consumption and expenditure, and inertia in switching, all contribute to the selection of a retail provider. Occupation and gender were not important.

