Post implementation review of the FTR market

Report

14 November 2019

Market Performance

Version control

Version	Date amended	Comments
1	14 Nov 2019	Version for SLT review
2	22 Nov 2019	SLT comments incorporated
3	24 April 2020	Board comments incorporated

Executive summary

Section 42 of the Electricity Industry Act 2010 (Act) specified several "new matters" to be addressed, one of which was "*mechanisms to help wholesale market participants manage price risks caused by constraints on the national grid".* To fulfil this requirement, the Electricity Authority (Authority) established a financial transmission rights (FTR) market with the first auction taking place in June 2013.

FTRs are a type of locational hedge covering the price difference between pairs of grid nodes, called hubs, and are funded by auction income and the settlement surplus. Price differences are caused by both transmission losses and grid constraints. Constraint effects tend to be less frequent and predictable but can be much more severe when they do eventuate. The FTR market has been progressively expanded from the initial two hubs to now cover eight hubs.

Overall the introduction of the FTR market has been a success. Evidence suggests that FTRs contribute to spot price risk management, increase the efficiency of other risk markets, have contributed to retail competition, and have been used in innovative ways that were not anticipated when FTRs were introduced.

While retail concentrations have clearly reduced in most regions, it is difficult to disentangle the effects of the FTR market from the many other initiatives of the past decade. Consequently, we interviewed participants about their use of the FTR market. The key findings were:

(a) Most FTR users consider them an effective tool to have in their risk management strategy, with several indicating FTRs play a significant role.

(b) Two respondents said FTRs had been a significant factor in enabling them to expand their retailing into new geographical areas.

(c) Half of FTR users said they had enabled them to underwrite or support other risk management products.

(d) Views on whether FTRs had reduced the cost of risk management ranged from a significant reduction, through some reduction, no effect to actually increasing cost.

(e) It is too early to tell whether FTRs will be a significant factor in generation location decisions. The relatively small amount of recent generation investment was likely committed before the start of the FTR market and has been driven mainly by proximity to fuel sources.

(f) No respondents said that FTRs had caused them to change the way they offer their generation into the market while one was unsure.

(g) A relatively small number of participants buy or trade FTRs. However, this may be more due to complexity, lack of education and other barriers rather than a lack of usefulness.

We used an econometric approach to test some of the claims made by survey respondents and found that:

(a) participants' FTR holdings are strongly correlated with their other spot market activity such as energy hedges, generation and demand, suggesting that FTRs do play a significant role in their operations

(b) certain FTRs can substitute for energy futures, providing another source of energy hedging and potentially increasing the liquidity and efficiency of both markets

(c) the price of FTRs between Benmore and Otahuhu closely follows the difference in the futures prices between these locations, suggesting that FTRs would increase the liquidity and efficiency of both markets

(d) speculators are likely to increase FTR liquidity.

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1 Post-implementation reviews assess the effectiveness of regulatory change

1.1 This report presents the Authority's post-implementation review of the FTR market. The purpose of a post-implementation review is to evaluate an initiative against its expected outcomes. From the Authority's perspective, this enables learning about how regulatory decisions—or decisions not to regulate—are affecting the sector and whether further policy action is required.

1.2 The methodology we use is to assess the outcomes of the FTR market against the expected benefits identified in the FTR market cost benefit analysis (CBA) and to identify any additional benefits that were not anticipated.

2 Introduction

2.1 We provide some background to the drivers that led to the establishment of the FTR market. We then discuss the origins of locational price risk (LPR) and the various alternative solutions to LPR that were considered before settling on FTRs. We then outline the particular features pertaining to New Zealand's FTR market.

2.2 We list the estimated costs and benefits from the original FTR CBA and discuss the most important of the benefits in turn, as well as providing some perspective on the scale of the claimed benefits.

2.3 We surveyed participants about their use of FTRs and discuss our findings.

2.4 Since FTR benefits are not directly observable, we use an econometric approach to identify relationships between participant FTR holdings and the various components of their wholesale market position.

2.5 We discuss some other observations about the FTR market.

2.6 Finally, we discuss some interactions with other projects and raise some questions for future consideration.

3 Background

3.1 One of the recommendations of the 2009 ministerial review of the electricity market was to:

> *Introduce, as a priority, a transmission hedging mechanism to assist retailers manage risks created by transmission congestion.*[1]

3.2 The reason stated for the recommendation was:

> *The risk of price spikes at offtake nodes caused by transmission congestion is a significant disincentive for retailers without generation assets in that region. Transmission hedges help manage that risk.*

3.3 The recommendation was subsequently captured in section 42 of the Electricity Industry Act 2010 (Act) as one of the new matters to be included in the Electricity Industry Participation Code (Code) within one year. However, the focus was broadened from retailers to all wholesale market participants:

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1 Improving electricity market performance - Summary note on recommendations, October 2009 (recommendation 18)

mechanisms to help wholesale market participants manage price risks caused by constraints on the national grid.[2]

3.4 The former Electricity Commission (Commission) had been investigating means to manage LPR, and this work was taken over by the Authority upon its establishment in 2010.

3.5 Code amendments establishing the FTR market arrangements were gazetted on 1 October 2011.

3.6 The first FTR auction took place in June 2013 with two FTR hubs at Benmore (BEN) in the South Island and Otahuhu (OTA) in Auckland.

3.7 Three additional FTR hubs were added in November 2014 at Haywards (HAY) near Wellington, Islington (ISL) in Christchurch and Invercargill (INV) in Southland.

3.8 A further three FTR hubs were added in May 2018 at Whakamaru (WKM) in the central North Island, Redclyffe (RDF) in the Hawkes Bay and Kikiwa (KIK) in Nelson/Marlborough.

4 Origin of Locational Price Risk

4.1 The wholesale electricity spot market calculates prices across some 250 locations (called nodes) in New Zealand.

4.2 Sources of electricity generation are often hundreds of kilometres away from electricity consumers. The transmission system used to transport electricity over long distances is subject to:

(a) loss of energy (this means more electricity must be generated than is consumed);

(b) congestion (where a shortage in the transmission capacity to supply the demand leads to more expensive sources of generation being used to supply electricity demanded); and

(c) risk of failure of critical elements (which means generation or demand reduction must be on standby to cover such an event, referred to as ‘instantaneous reserves’).

4.3 These factors can result in large unpredictable price differences across the electricity grid resulting in LPR.

4.4 Vertically integrated generator-retailers (“gentailers”) sell energy to the clearing manager at the nodes where their generation is located and must purchase energy back from the clearing manager at the nodes where they sell to their retail customers.

4.5 This exposes gentailers to the spot price differences between those locations.

4.6 As a result, prior to about 2009, gentailers tended to concentrate their retailing activity close to their generation.

4.7 Similarly, standalone retailers are exposed to the spot price differences between central trading hubs where they can purchase energy hedges and the nodes where they sell to their retail customers.

4.8 Large consumers on spot price contracts are also exposed to the spot price differences between central trading hubs where they can purchase energy hedges and the nodes where they take supply from the grid.

2 Electricity Industry Act 2010, section 42, clause (2)(c)

4.9 Standalone generators could also be exposed to the spot price differences between the nodes where they generate and the nodes where they are able to sell energy hedges.

4.10 Nodal prices increase progressively as one moves through the grid from generation locations towards demand locations. This means that, in aggregate, more money is collected from purchasers than is required to pay generators, resulting in a settlement surplus known as the loss and constraint excess (LCE). LCE is sometimes referred to as transmission rentals or locational rentals.

4.11 Prior to the FTR market the LCE was allocated to transmission customers in proportion to their transmission charges.

4.12 Generation and demand in a similar location can provide a "natural" hedge for each other because they both face similar spot prices.

4.13 But the portion of demand and generation that are remote from each other do not necessarily provide a "natural" hedge because of the presence of LPR. The LCE exactly corresponds to this difficult-to-hedge portion of LPR. Hence the LCE provides a natural source of funding for an LPR solution.

5 A number of alternative solutions to managing LPR were considered

5.1 A number of alternative means of managing LPR were considered by the Commission and the Authority. These broadly fall into the following categories:

(a) a locational rental allocation (LRA), which allocates defined locational rentals to spot market purchasers in proportion to their locational price risk using a formula

(b) FTRs, which are auctioned to the highest bidder and essentially provide the holder with a claim to the locational rentals on transmission circuits specified in the FTR

(c) a hybrid of LRAs and FTRs, in which inter-regional rentals are allocated using an FTR and intra-regional rentals are allocated with separate LRAs in each region

(d) zonal pricing, under which demand (and possibly generation) at all nodes within a zone are subject to the same price.

5.2 For reasons of flexibility, scalability, tradability, coverage, and efficiency of price signals, the Authority initially settled on and implemented an inter-island FTR and subsequently a multi-point FTR market.

6 Features of the NZ FTR market arrangements

6.1 FTRs are financial hedges that help energy purchasers and generators to manage price volatility between different locations across the grid.

6.2 FTRs are monthly base load products. Each month is referred to as an FTR period.

6.3 FTR capacity is progressively released over a 26-month horizon, as information about grid availability becomes more certain.

6.4 FTR auctions occur twice a month, with each auction covering six future FTR periods. Thus, each FTR period is auctioned 12 times over the product horizon.

6.5 There are currently eight FTR hubs defined (Otahuhu, Whakamaru, Redclyffe, Haywards, Kikiwa, Islington, Benmore and Invercargill).

6.6 FTRs are defined between a source hub and a sink hub, eg, in this document an FTR designated as BEN_OTA indicates BEN is the source hub and OTA is the sink hub.

6.7 There are two types of FTR:

(a) Obligation FTRs: The holder pays the auction price for the FTR. At settlement, for each trading period within the FTR period where the sink price exceeds the source price, the clearing manager must pay the FTR holder the difference. For each trading period where the source price exceeds the sink price, the FTR holder must pay the clearing manager the difference.

(b) Option FTR: Similar to an Obligation FTR except that for trading periods where the source price exceeds the sink price, no payment is made.

6.8 FTRs are funded by the FTR auction revenue and a portion of the LCE.

6.9 If there are insufficient funds in any month to settle FTRs in full, the settlement payments (both positive and negative) are scaled back as required. However, such scaling back of settlement payments has only occurred twice over the six or so years of the FTR market's existence.

7 Estimated Costs and Benefits of the FTR market

7.1 The estimated costs and benefits from the consultation paper for the initial inter-island (2-hub) FTR regime are summarised in Table 1 and Table 2 respectively.[3]

Table 1: Estimated costs of initial inter-island FTR regime

Type	Frequency	Low scenario	High scenario
Development and implementation costs (Authority, Market operator, Transpower and clearing manager)	Initial	\$2.4M	\$4.8M
Set up costs to market participants (total)	Initial	\$1M	\$3M
Operating costs to FTR manager, clearing manager, Transpower	Ongoing	\$1.5M per year	\$2M per year
Operating costs to market participants (total)	Ongoing	\$750k per year	\$1.9M per year

Source: Electricity Authority

7.2 The design of the initial inter-island FTR regime and the establishment of the associated regulatory and institutional framework allowed other FTRs to be readily introduced in future. The initial inter-island FTR was estimated to cover 67% of total LPR. Therefore, an option value was included for half the value of addressing the remaining 33% of LPR.

3 Consultation Paper Managing locational price risk: Proposed amendments to Code, 28 April 2011 on webpage https://www.ea.govt.nz/about-us/what-we-do/our-history/archive/dev-archive/work-programmes/market-wholesale-and-retail-work/ftr-development/consultation/#c8176

7.3 This implies an upper bound on (static) benefits 50% larger (ie. 100% / 67%) than the benefits listed in Table 2 if the FTR regime was eventually extended to cover 100% of LPR.

Table 2: Estimated benefits of initial inter-island FTR regime

Type	Frequency	Low scenario	High scenario
Greater use of locational hedging (transfer)	Ongoing	Transfer between market participants, no net benefits	Transfer between market participants, no net benefits
Lower search and transaction costs for locational hedge contracts	Ongoing	$56k per year	$169k per year
More retailers supplying electricity to regions subject to locational price risk, resulting in greater competition—allocative efficiency benefits	Ongoing	0.5% reduction in average retail price providing allocative efficiency benefits of $5k per year	1% reduction in average retail price providing allocative efficiency benefits of $20k per year
More retailers supplying electricity to regions subject to locational price risk, resulting in greater competition—productive efficiency benefits	Ongoing	0.25% reduction in average retail price providing productive efficiency benefits of $3.9M per year, phased in over five years	0.5% reduction in average retail price providing productive efficiency benefits of $7.8M per year, phased in over five years
More generators locating in regions subject to locational price risk, resulting in greater competition—allocative efficiency benefits	Ongoing	0.25% reduction in average retail price providing allocative efficiency benefits of $1.25k per year	0.5% reduction in average retail price providing allocative efficiency benefits of $5k per year
More generators locating in regions subject to locational price risk, resulting in greater competition—productive efficiency benefits	Ongoing	0.09% reduction in average retail price providing productive efficiency benefits of $1.9M per year, phased in over five years	0.16% reduction in average retail price providing productive efficiency benefits of $3.9M per year, phased in over five years
Lower search and transaction costs for other hedge market products	Ongoing	$5.6k per year	$67.5k per year
Efficiency gains from improved price signals	Ongoing	$3.4k per year	$14.1k per year
Option value provided by inter-island FTR	Ongoing	25% of above benefits[4]	25% of above benefits[4]
Dynamic efficiency benefits	Ongoing	Not quantified	Not quantified

Source: Electricity Authority

4 The consultation paper showed this as 16.7% (ie. 0.5 x 33%), but it should have been 25% (ie. 0.5 x 33% / 67%)

8 Assessment of claimed benefits

Several initiatives have helped increase regional retail competition since 2009

8.1 As indicated in section 3, the primary driver for introducing FTRs was to increase retail competition by reducing the risks for retailers operating in locations where they have no generation or access to hedges.

8.2 An analysis of regional retail market shares shows that retail competition has indeed improved significantly over the last ten years or so.

8.3 The change in regional market shares of the five largest retailers and the combined share of the remaining retailers since 2003 is shown in Figure 1 through Figure 5. Note the horizontal axis markers indicate the end of the stated year.

8.4 Beginning in around 2009, the market shares of the incumbent retailers have reduced significantly while those of the other retailers have increased, resulting in a more competitive retail environment.

8.5 However, there has been a whole suite of changes, in addition to FTRs, which have likely contributed to this outcome. These changes are as follows: [5]

(a) Virtual Asset Swaps (VAS) (15-year contracts) were established between Meridian Energy Limited (Meridian) in the South Island and each of Genesis Energy Limited (Genesis) (51.3 MW) and Mercury Energy Limited (formerly Mighty River Power Limited) (79.8 MW) in the North Island ramping up from 1 January 2011

(b) Tekapo A and B power stations were transferred from Meridian to Genesis on 1 June 2011 [6]

(c) Improvements to the Australian Securities Exchange (ASX) NZ electricity futures and options market, including:

(i) Voluntary market-making arrangements with a maximum spread established in October 2011. The arrangements have evolved over time; most recently in mid-2019 amendments were made to improve resilience in times of market stress

(ii) Monthly and peak products introduced in December 2013

(iii) Monitoring and reporting on market trade volumes, price trends and open interest

(iv) Contract size lowered from 1 MW to 0.1 MW on 1 November 2015. This brought the contract size in line with the FTR market and was more suitable for smaller retailers.

(d) The Act lowered barriers to enable lines companies to retail subject to certain conditions

(e) Efforts to improve standardisation of distributors' use-of-system agreements and tariff structures

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5 Some of these came out of the ministerial review while others progressed work begun by the Commission.

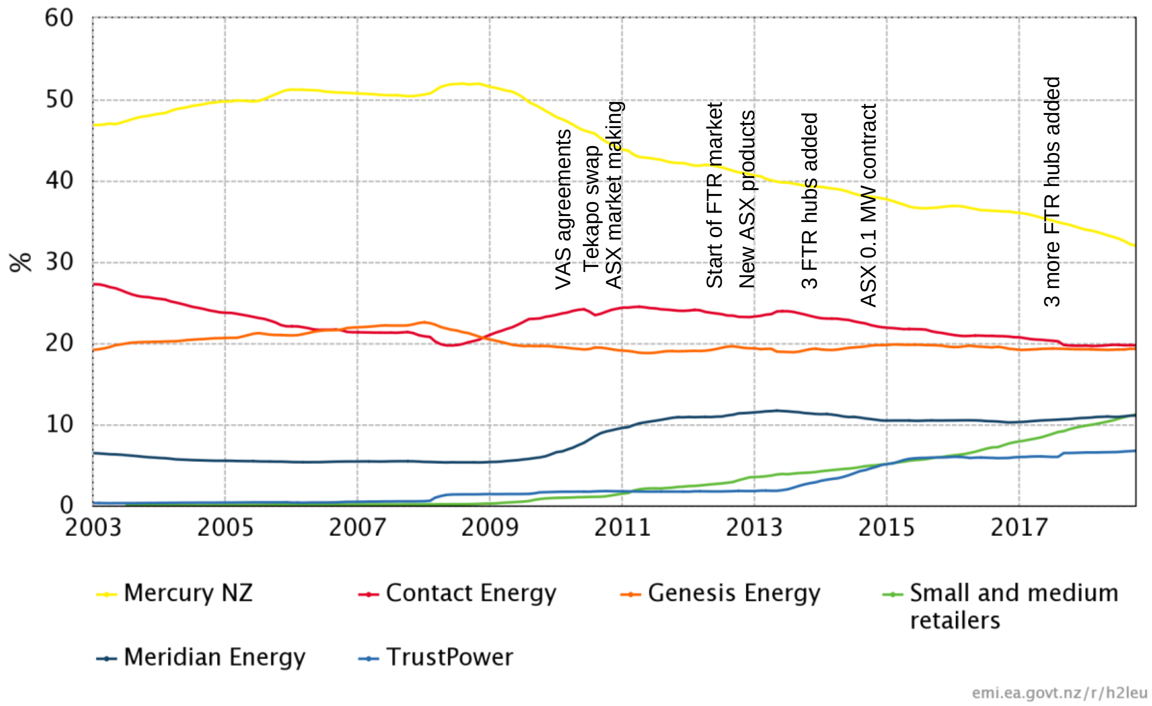
6 The transfer of Whirinaki from the Crown to Meridian was also recommended but did not eventuate, Whirinaki eventually being purchased by Contact Energy Limited.

(f) Shortening the maximum timeframes for switching between retailers

(g) A fund was established to promote customer switching (What's My Number campaign) and improve the capability of Consumer NZ's Powerswitch website.

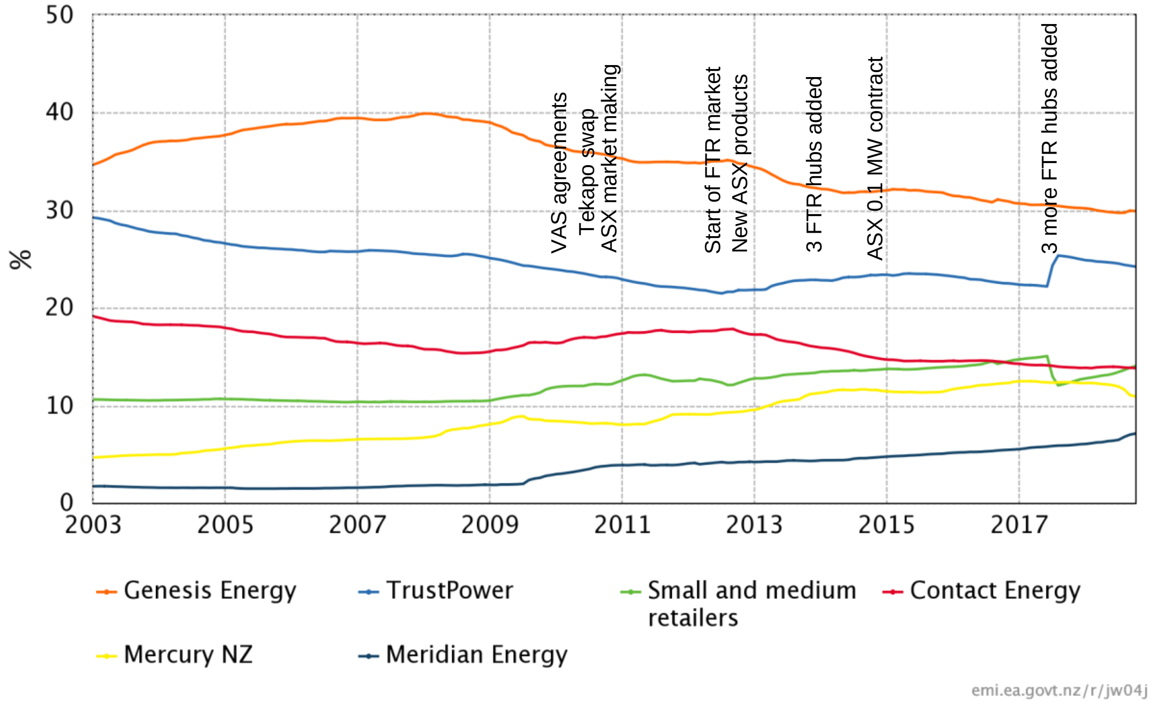
8.6 Consequently, it is difficult to disentangle the incremental benefits specifically due to the FTR market.

Figure 1: Upper North Island retail market share trends



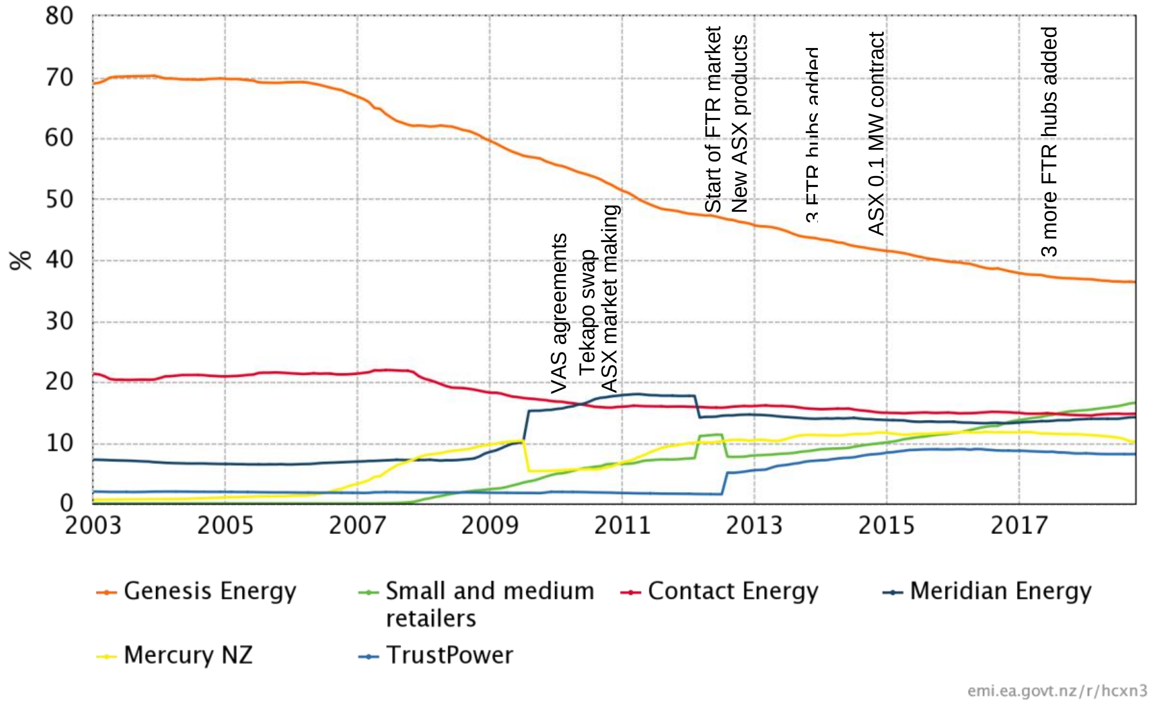
Source: Electricity Authority

Figure 2: Central North Island retail market share trends



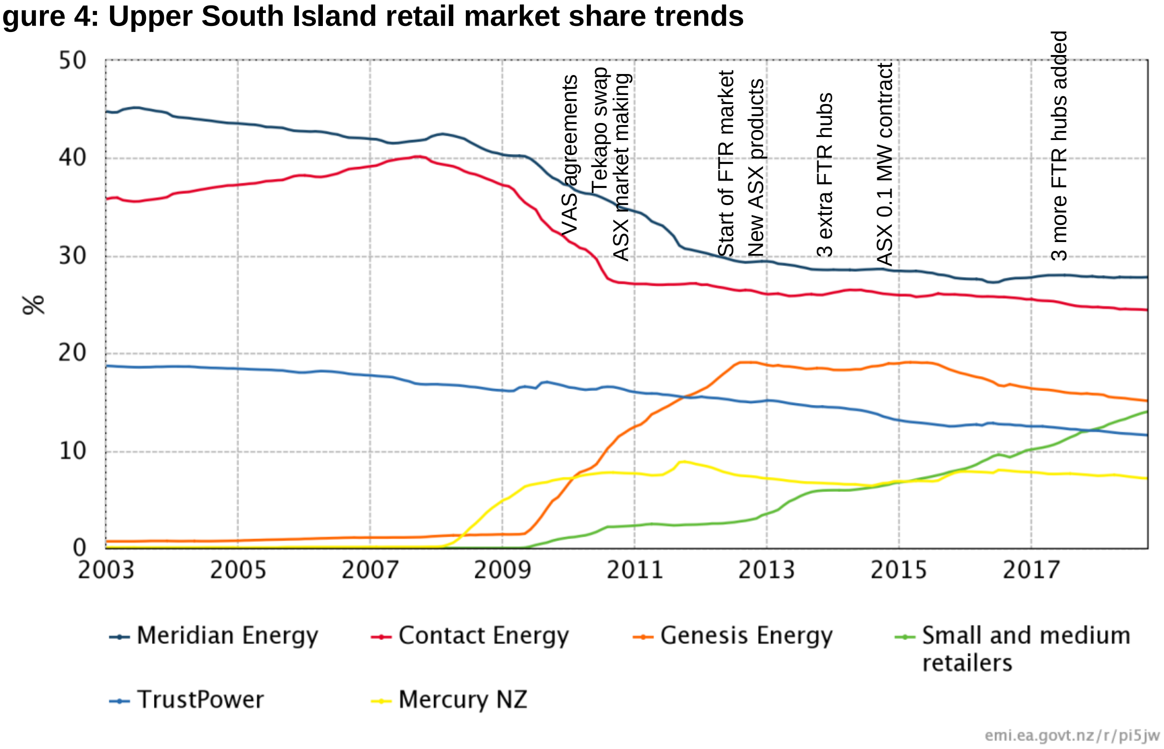
Source: Electricity Authority

Figure 3: Lower North Island retail market share trends



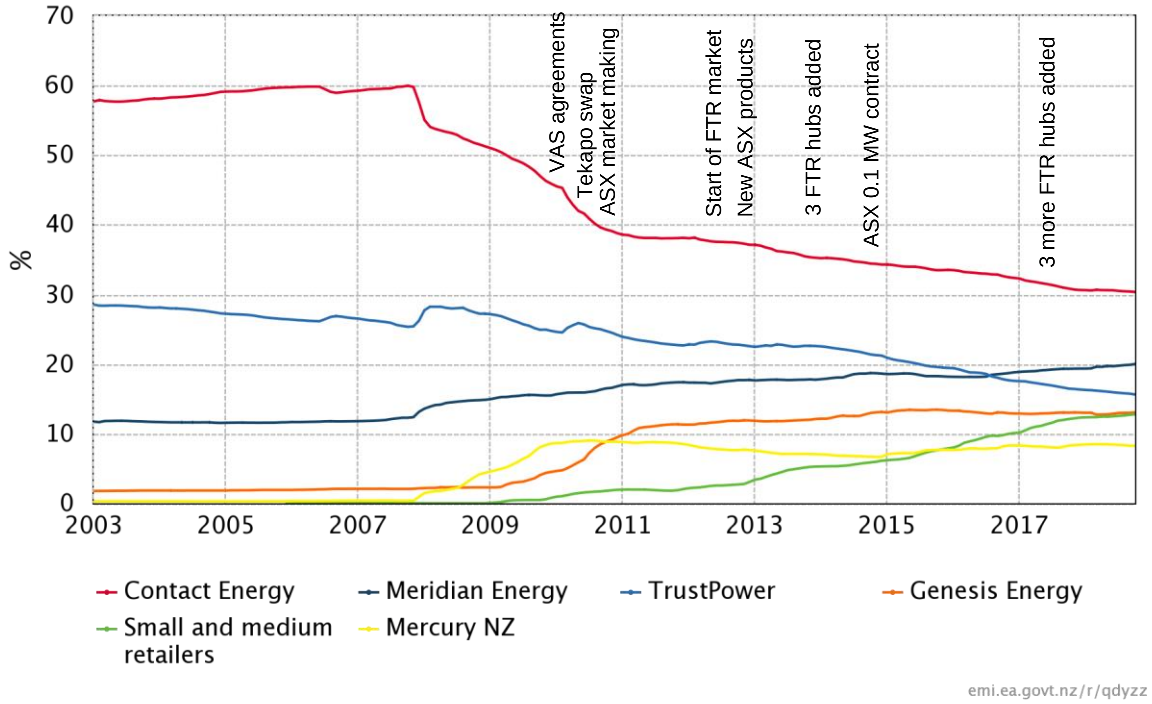
Source: Electricity Authority

Figure 4: Upper South Island retail market share trends



Source: Electricity Authority

Figure 5: Lower South Island retail market share trends



Source: Electricity Authority

No discernible effect on regional generator competition as yet

8.7 As indicated in the cost benefit analysis (section 7), major benefits were also predicted from increased generator competition due to generators locating in regions subject to locational price risk.

8.8 In the six years since the start of the FTR market there has been relatively little generation investment. This can be attributed to the essentially flat demand growth over this period.

8.9 Significant power stations commissioned since 2013 are listed in Table 3.

Table 3: Significant power station's commissioned since start of FTR market

Power scheme	Owner	Technology	Location	Date commissioned
Ngatamariki	Mercury	Geothermal	Central North Island	2013
Amethyst	Westpower	Hydro	West Coast	2013
Esk	Trustpower	Hydro	Hawkes Bay	2013
McKee	Todd	Gas Turbine	Taranaki	2013
Te Mihi	Contact	Geothermal	Central North Island	2014
Mill Creek	Meridian	Wind	Wellington	2014

Source: Electricity Authority

8.10 In all cases, the primary factor driving location is proximity to fuel, ie, geothermal steam, wind, water or natural gas. And in most cases the generator already had power stations in the area.

8.11 Furthermore, it is likely the decisions to proceed with these investments would have been made prior to the establishment of the FTR market.

8.12 Hence, it is unlikely the FTR market had any impact on any of these investments.

8.13 This is consistent with responses from the customer survey: no respondents said FTRs had helped them locate generation in new areas.

8.14 Time will tell if FTRs are a significant factor in generators' investment decisions as the anticipated electrification of the process heat and transport sectors boosts demand over coming decades.

No large direct consumers use FTRs

8.15 The wording in section 42 the Act refers to assisting wholesale market participants more generally. This would include large direct consumers on spot price contracts, since they are also exposed to LPR between central trading hubs where they can purchase energy hedges and the nodes where they take supply from the grid.

8.16 However, none of the five large direct consumers who took part in the survey said they purchase FTRs, either directly or through a broker, often citing that they didn't have the resource to devote to the complexities of the electricity market let alone FTRs.

8.17 However, they are likely still benefitting indirectly through the increased efficiency and liquidity FTRs bring to other contract markets, as discussed in section 10.

Lower search and transaction costs for locational hedges and other hedge products

8.18 It stands to reason that the FTR market will have reduced search costs for locational hedges since there was previously no centralised platform for these products.

8.19 It is likely that the FTR market has also reduced search costs for energy hedges due to the increased efficiency and liquidity FTRs bring to these other contract markets, as discussed in section 10.

8.20 No attempt has been made to quantity the benefits achieved.

No efficiency gains from improved price signals

8.21 One of the benefits anticipated in the CBA was that access to locational hedges would reduce participants' incentives to move spot prices away from efficient levels.

8.22 To quote from the CBA:

> *Under the status quo, a party that is not hedged against LPR faces incentives across their entire load or generation* [in a region] *to alter their load or generation to avoid the impact of price changes caused by constraints. This is not efficient because nodal prices are intended to provide a price signal on the margin rather than for a participant's entire load or generation. A party that covers their LPR with an FTR will only face incentives to alter their load or generation in relation to the portion not covered by the FTR, which means they are facing the correct price signal.*

8.23 We asked survey respondents if FTRs had changed the way they offer their generation. Of the four surveyed gentailers who use FTRs, three said FTRs had not changed their offer behaviour while the fourth was unsure.

8.24 One reason for this might be that exercising one's market power to prevent constraints from binding is a cheaper alternative (from the participant's perspective) than purchasing FTRs or other hedges. This was effectively Meridian's strategy in the 2 June 2016 Trading Conduct breach.[7]

8.25 In its decision paper regarding that particular breach allegation the Authority noted that it would have expected Meridian to have covered its risk using other available risk management products or if it chose not to do that then bear the cost of the risk if it eventuates.[8]

8.26 Another reason that FTRs have not changed generator offer behaviour might be that insufficient FTRs are available to fully cover one's exposure.

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7 Market performance review: High prices on 2 June 2016, 18 December 2017 on webpage https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2016/high-energy-prices-2-june-2016/

8 4May17-Meridian-discontinue-investigation.pdf on webpage https://www.ea.govt.nz/code-and-compliance/compliance/decisions/investigations-closed-no-settlement-reached/

Sanity check on scale of claimed benefits

8.27 The FTR market does not create money in and of itself; it merely redirects it (a portion of the LCE) to, hopefully, a more valuable use.

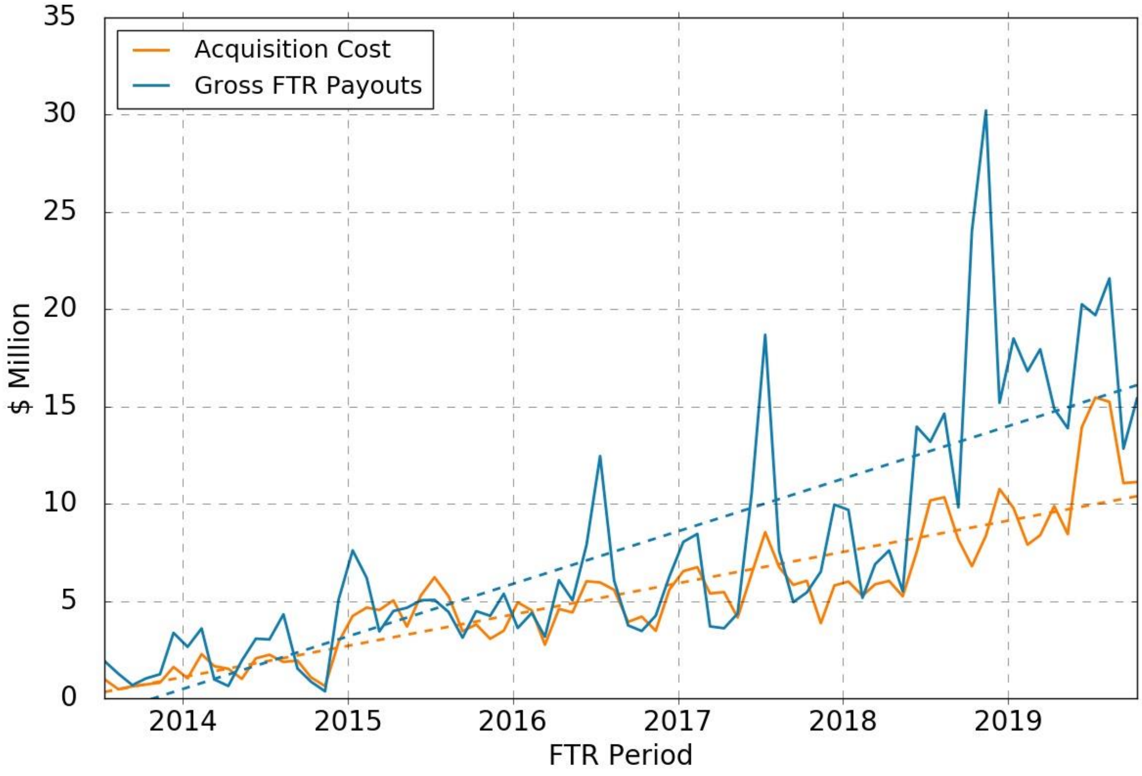
8.28 But intuition suggests that the value created by redirecting LCE to a more valuable use would be significantly less than the face value of the funds reallocated.

8.29 By July 2019, acquisition costs, the money FTR participants pay to acquire FTRs, had trended up to an average of around $10.4M per month or $125M per year, while gross FTR payouts (FTR hedge value) had trended up to an average of around $16.1M per month or $193M per year (Figure 6). We can assess the "size" of the FTR market in terms of cash flows as the greater of these two figures.

8.30 From Table 2, the estimated benefits from increased retail competition range from $3.9M to $7.8M per year, phased in over five years. (This is the largest of the claimed benefits for which there is some supporting evidence.)

8.31 Thus, the claimed benefits amount to between two and four percent of the size of the FTR market, which seems within the bounds of reasonableness.

Figure 6: Total monthly acquisition costs and gross FTR payouts



Source: Electricity Authority

Notes: 1. Regression lines shown dashed

9 We interviewed participants about their use of the FTR market

9.1 Due to the difficulty in disentangling the incremental effects of the FTR market, we decided to interview participants directly.

9.2 The survey was carried out by UMR Research to maintain anonymity.

9.3 20 wholesale market participants were interviewed in late 2017 including gentailers, standalone retailers, financial entities and large direct consumers.

9.4 The key findings of the survey include the following:

(a) There appears to be a limited market for FTRs, with less than half of those interviewed buying or trading them. This may be more due to complexity, lack of education and other barriers to entry as noted in paragraph 9.5 rather than a lack of usefulness.

(b) Most FTR users consider them an effective tool to have in their risk management strategy. Of the seven gentailers and standalone retailers who use FTRs, five indicated that FTRs play a significant role in their risk management strategy.

(c) Views on whether FTRs had reduced the cost of risk management ranged from a significant reduction, through some reduction, no effect to actually increasing cost.

(d) Two respondents said FTRs had been a significant factor in enabling them to expand their retailing into new geographical areas.

(e) FTRs have not helped any gentailers locate generation in new areas or caused a change in the way they offer their generation into the market.

(f) Half of the gentailers, standalone retailers and financial entities who use FTRs said that using FTRs had enabled them to underwrite or support other risk management products.

9.5 We also asked interviewees to offer suggestions for improving the FTR market. Common themes included the following:

(a) Adding more FTR nodes. A central north island node was a common suggestion—note that a Whakamaru node has been added since the interviews took place. A few respondents thought there should be significantly more nodes.

(b) There were a range of views on the complexity of the FTR market. At one extreme, some respondents felt the market was already too complex, required an inordinate amount of resource to manage and interact with, and that an LRA type regime would be better. At the other extreme, some respondents believed there was a certain level of complexity that would have to exist for the market to serve its purpose, and that, since participation was voluntary, if incumbents had high-cost outdated systems this shouldn't be a reason to hold back the competitive market. In between were those who felt a balance could be achieved by adding a few more, strategically located nodes.

(c) A need for more education, particularly for smaller, less sophisticated firms. One respondent didn't seem to be aware that the clearing manager publishes daily settlement prices—estimates of current market value—for all FTR products.

(d) Barriers to entry. A few respondents felt the complexity of the FTR market was a barrier to participation by smaller, less sophisticated firms, and as a result had tended to help incumbents more than new entrants. Ideas to improve this included:

(i) Making the market as accessible as possible

(ii) Education

(iii) Helping smaller organisations establish relationships and contacts with larger organisations to help them enter the FTR market. Some did not appear to be aware that OMF provides a broking service.

(e) A few respondents suggested a need for more frequent auctioning.

9.6 The full survey report is included in Appendix A.

10 Analysis of survey findings

10.1 We used an econometric approach to try to confirm some of the claims made by FTR users in the survey.

FTR holdings are correlated with other wholesale market activity

10.2 Several respondents stated that they use FTRs to mitigate risk over their electricity portfolio.

10.3 To test this, we ran a regression of each participant's inter-island FTR holdings against the various components of their wholesale market position:[9,10]

(i) Nett NI energy hedge position[11]

(ii) NI generation

(iii) NI demand

(iv) Nett SI energy hedge position[11]

(v) SI generation

(vi) SI demand

(vii) Nett energy option position[12]

10.4 Total inter-island FTRs held each month was included as a control variable. This depends on whether there are any significant HVDC outages during the month as well as on the FTR grid scaling factor.

10.5 Scaling factors limiting the effective capacity of the transmission grid are used to help ensure the FTR market is revenue adequate. These scaling factors have been adjusted several times since the market began (see Table 4).

10.6 Dummy variables were added to the regression model to allow for any change of behaviour that may have occurred due to the scaling factor changes on January 2015 and November 2016. The earlier changes are ignored since they occurred so close to the start of the FTR market.

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9 All variables measured in MWh

10 FPVV and FPFV contracts are excluded as it is assumed they are already accounted for in demand

11 CFDs and ASX futures from the Electricity Hedge Disclosure System (defined as positive for sell, negative for buy)

12 Locational information is not specified for option products in the Electricity Hedge Disclosure System (defined as positive for sell, negative for buy)

Table 4: FTR grid scaling factors

Factor applicable when outage file is available	First applicable FTR period	Comment
54%	July 2013	
61%	August 2013	
68%	September 2013	
72%	January 2015	FTR capacities for bipole outage states were also increased
83%	November 2016	

Source: Electricity Authority

10.7 These dummy variables are used directly (eg. postJan2015) and also multiplied by the total inter-island FTRs (eg. FtrTotal:postJan2015).

10.8 The regression results are shown in Table 5. In general, the set of variables included in the model has been chosen to maximise the Adjusted R squared in each case.

10.9 Coefficient estimates are shown to one significant figure and P-values are colour-coded to indicate the reliability of the estimate (increasingly blue for $P < 0.05$, and increasingly red for $P > 0.05$).

10.10 R squared and Adjusted R squared are also shown.

10.11 Firms with less than 20 observations or whose only wholesale market activity is FTR trading have been excluded.

10.12 The signs of the model coefficients indicate that in some cases FTRs are being used as substitutes (negative correlation), while in other cases they are complements (positive correlation).

10.13 For example, firm A has a positive coefficient for NI hedge sales with respect to SI to NI FTRs (ie. positively correlated), indicating they tend to move in the same direction. Thus, the more SI to NI FTRs firm A holds, the more NI hedges they are able to sell (or fewer NI hedges they need to buy). Thus, the FTRs and hedges tend to offset each other's spot price risk.

10.14 Firm A's coefficient for NI hedge sales with respect to NI to SI FTRs has the opposite sign, again indicating that they offset each other's spot price risk.

10.15 Similarly, firm A's NI generation is positively correlated with its NI to SI FTRs and negatively correlated with its SI to NI FTRs, both of which are consistent with offsetting of spot price risk.

10.16 All coefficients that are consistent with offsetting of spot price risk between the associated wholesale market variable and the FTR are indicated with a green ring. These include positive coefficients for source island generation and sink island demand and hedge sales; and negative coefficients for sink island generation and source island demand and hedge sales. 22 of the coefficients fall into this category.

10.17 We shall ignore energy options in this discussion as we don't know their location. The remaining 24 coefficients in the wholesale market group, ie, ignoring those related to FTR availability, are inconsistent with offsetting of spot price risk between the associated variable and the FTR. This could indicate that the participant is seeking to increase their exposure to spot prices in these cases, which would be more consistent with a speculative rather than a hedging strategy.

10.18 A number of respondents indicated they did trade FTRs in a speculative fashion.

10.19 While such speculative activity may not directly promote retail competition it is likely to have indirect benefits through increasing liquidity in the associated markets.

Table 5: Regression results for participant inter-island FTR holdings

	Firm -->	A				B				C				D				E				F				G			
	FTR direction -->	N to S		S to N		N to S		S to N		N to S		S to N		N to S		S to N		N to S		S to N		N to S		S to N		N to S		S to N	
	Predictor	coeff	P>|t|	coeff	P>|t|	coeff	P>|t|	coeff	P>|t|	coeff	P>|t|	coeff	P>|t|	coeff	P>|t|	coeff	P>|t|	coeff	P>|t|	coeff	P>|t|	coeff	P>|t|	coeff	P>|t|	coeff	P>|t|	coeff	P>|t|
Wholesale market	HedgeNI	-0.4	0.002	0.6	0.000	-0.2	0.001	-0.04	0.011			-0.2	0.039	-0.2	0.058			0.4	0.065			0.1	0.179	-0.2	0.050			-0.4	0.099
	GenNI	0.2	0.021	-0.2	0.000	0.1	0.000	0.02	0.010					0.1	0.030	0.1	0.003	0.1	0.286			-0.2	0.034						
	DemNI	0.4	0.053					-0.04	0.037	-0.1	0.077	-0.3	0.026			-0.1	0.064					-0.7	0.156						
	HedgeSI	-0.4	0.009			-0.1	0.232							-0.1	0.228	-0.5	0.000	-0.5	0.007	0.1	0.201	0.2	0.016			0.4	0.159	-0.5	0.043
	GenSI	0.2	0.035	-0.2	0.024			0.03	0.116	-0.04	0.036	0.06	0.212					-0.2	0.200					-0.5	0.203				
	DemSI	-0.4	0.203					0.1	0.066			-0.05	0.201	-0.4	0.226							1	0.025	-0.3	0.018				
	Option			0.6	0.000	0.0	0.179	0.01	0.205			-0.1	0.154					-1	0.124							0.5	0.011		
FTR availability	FtrTotal	0.2	0.000	0.3	0.000	0.06	0.080	0.03	0.000	0.2	0.000	0.1	0.067	0.2	0.000	0.2	0.000	0.2	0.000	0.02	0.036					0.2	0.024		
	postJan2015	3.E+04	0.024			5.E+04	0.038					-5.E+04	0.039							1.E+04	0.001			-3.E+03	0.002				
	FtrTotal:postJan2015					-0.2	0.012	-0.02	0.000	-0.04	0.080	0.1	0.245	-0.05	0.067	-0.1	0.000	-0.1	0.002			0.008	0.007						
	postNov2016					-7.E+04	0.007			2.E+04	0.116									-8.E+03	0.005			2.E+03	0.062				
	FtrTotal:postNov2016			-0.1	0.000	0.2	0.021	-0.004	0.087	-0.08	0.023	0.1	0.000	0.06	0.001			-0.07	0.000			-0.005	0.107						
	R squared	0.646		0.714		0.422		0.518		0.523		0.830		0.621		0.587		0.566		0.457		0.681		0.462		0.492		0.879	
	Adjusted R squared	0.598		0.686		0.333		0.443		0.476		0.803		0.577		0.553		0.507		0.422		0.604		0.376		0.397		0.828	

Source: Electricity Authority

Notes:
1. Coefficient estimates are shown to one significant figure
2. P-values are colour-coded to indicate the reliability of the estimate (increasingly blue for P < 0.05, and increasingly red for P > 0.05)
3. Firms with less than 20 observations or whose only wholesale market activity is FTR trading are excluded
4. Hedge and option positions are defined as positive/negative for a net sell/buy positions respectively
5. Green rings indicate coefficients that are consistent with offsetting of spot price risk between the associated wholesale market variable and the FTR

Certain FTRs can substitute for energy hedges

10.20 One survey respondent stated that they use FTRs to manage energy as well as locational risk.

10.21 We looked at the correlation between settlement prices on different FTR paths and monthly average spot prices at different nodes.

10.22 We found that prices for certain FTR paths are quite highly correlated with nodal energy prices—typically those paths where power tends to flow in one direction and congestion is rare.

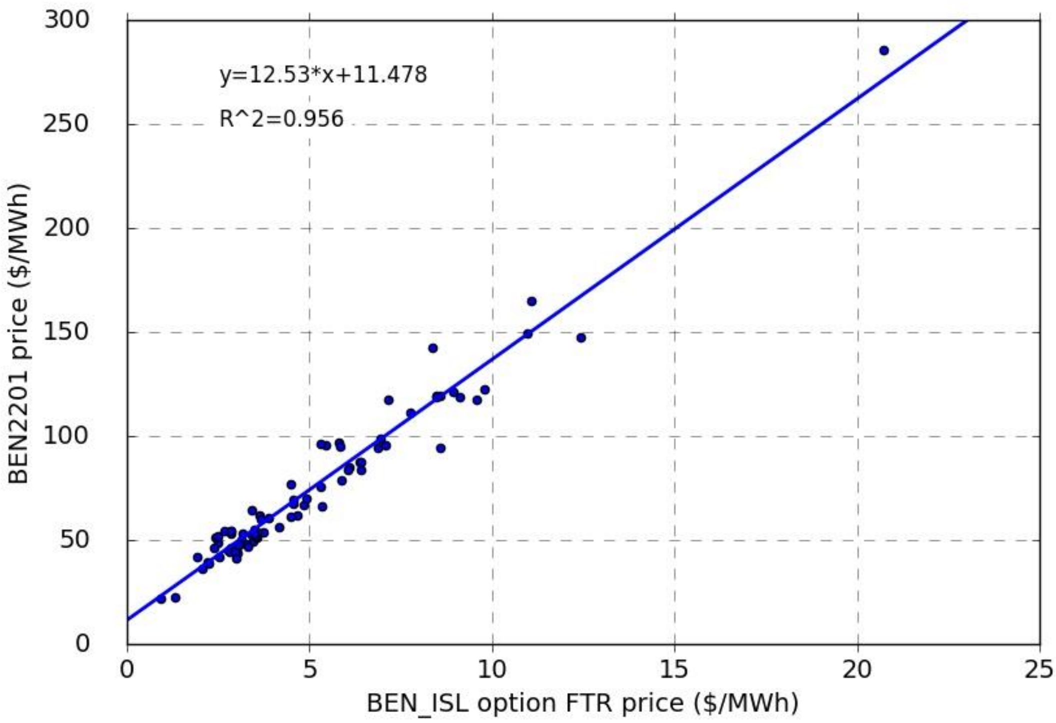
10.23 The reason for this is that the inter-nodal price differences, which FTRs cover in the New Zealand market, include marginal loss effects as well as congestion effects. And the loss effect, which makes up the majority of price differences—particularly on the AC grid—is proportional to the nodal energy price.

10.24 Figure 7 shows scatter plots for three combinations of nodes and FTR paths together with the linear regression line, equation and R^2.

10.25 Each dot represents one month since the start of the FTR market. FTR settlement prices for months prior to the relevant hubs being added to the FTR regime have been inferred from the nodal prices.

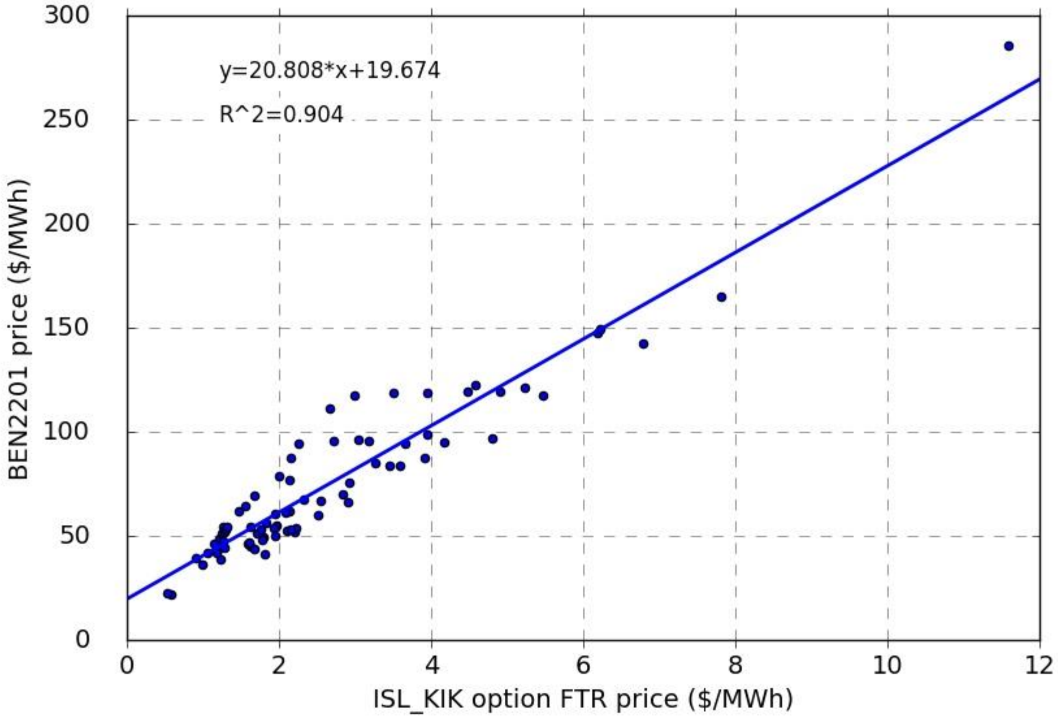
Figure 7: Nodal vs FTR settlement prices

(a) BEN2201 vs BEN_ISL Option FTR



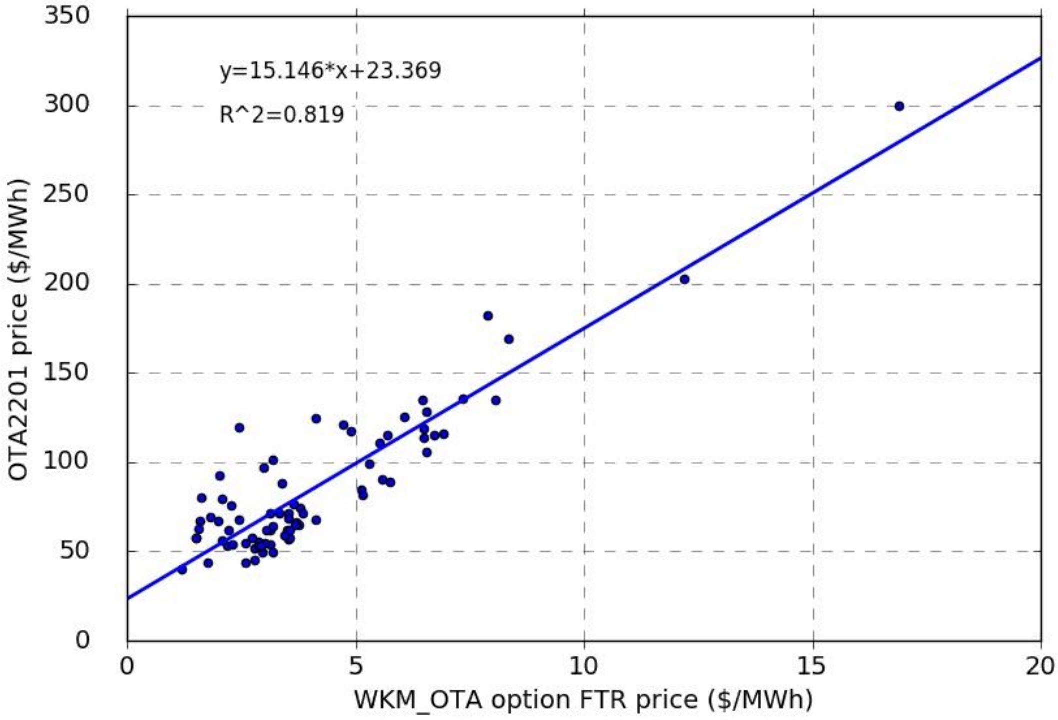
Source: Electricity Authority

(b) BEN2201 vs ISL_KIK Option FTR



Source: Electricity Authority

(c) OTA2201 vs WKM_OTA Option FTR



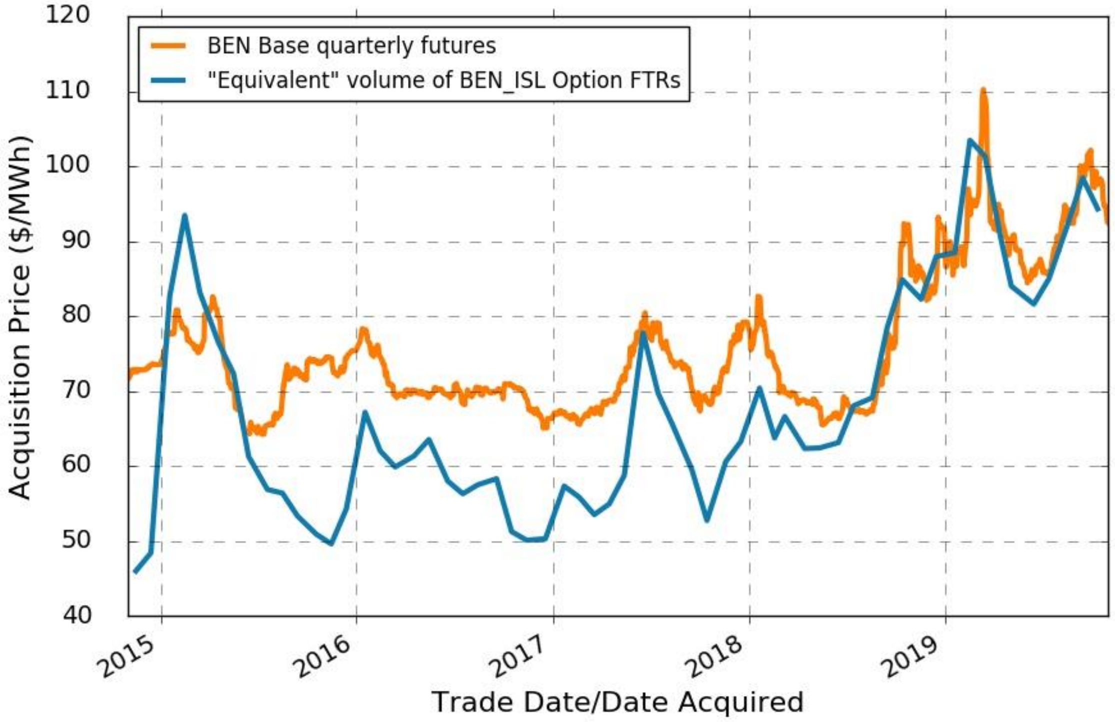
Source: Electricity Authority

10.26 Thus, certain FTRs can function reasonably well as a substitute for an energy hedge or to offset a position on the futures market for example.

10.27 However, the quantity of energy that can be hedged in this way is likely to be limited to a few percent of system demand. This is because FTRs are mainly funded by the LCE, which only amounts to two or three percent of total spot market revenue. Thus, this strategy is unlikely to be sustainable at significant scale.

10.28 Figure 8 compares the price of acquiring BEN futures versus the “equivalent” volume of BEN_ISL FTRs, where the price of the “equivalent” volume of FTRs is derived by applying the regression equation from Figure 7(a) to the FTR acquisition price, ie, equiv. price = 12.53 x FTR acq. price + 11.48.

Figure 8: Acquisition price of futures versus equivalent volume of FTRs



Source: Electricity Authority

Notes: 1. Prices for primary and variation FTR auctions occurring within each month are averaged to give a smoother curve

10.29 The orange curve is the forward price curve from EMI for BEN quarterly base futures averaged over all maturities traded each day.[13] The blue curve is derived from the acquisition price for BEN_ISL option FTRs averaged over all FTR periods traded within each month. Prices for primary and variation auctions occurring within each month are averaged to give a smoother curve.[14]

13 www.emi.ea.govt.nz/r/xpryo

14 There are two auctions every month. The first is called the primary auction. The second is called the variation auction.

10.30 It appears from the graph that the “equivalent” volume of FTRs tends to trade at a discount to the futures, except when the market is under a degree of stress as indicated by elevated prices.

10.31 The discount has been less apparent during the sustained high energy prices of the last twelve months or so.

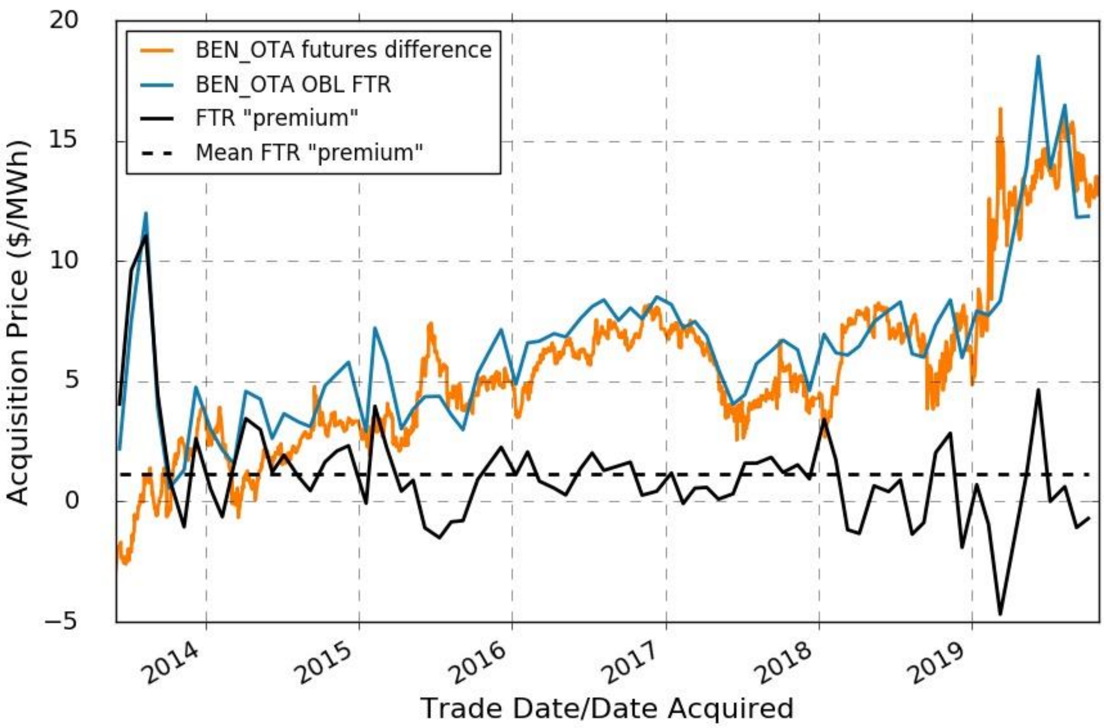
BEN_OTA FTRs trade at a similar price to the futures differential

10.32 Several respondents indicated they purchased FTRs in order to offset risks in the futures market or arbitrage the spreads between FTRs and futures. This activity would likely increase liquidity in both the futures and FTR markets.

10.33 A BEN_OTA obligation FTR is numerically equivalent to an OTA “buy” futures contract plus a BEN “sell” futures contract, ie, the nett settlement value is identical. Thus, it is possible to construct a synthetic BEN_OTA obligation FTR by respectively buying and selling equal quantities of OTA and BEN futures.

10.34 Figure 9 compares the price of acquiring the actual FTR versus the synthetic equivalent.

Figure 9: Price comparison of actual and synthetic BEN_OTA FTRs



Source: Electricity Authority

Notes: 1. Prices for primary and variation FTR auctions occurring within each month are averaged to give a smoother curve

10.35 The orange curve is the price of the synthetic FTR, ie, the difference between the forward price curves from EMI for OTA [15] and BEN [16] quarterly base futures averaged over all maturities traded each day.

[15] www.emi.ea.govt.nz/r/myo5b

10.36 The blue curve is the price of the actual FTR. Since obligation FTRs tend to be infrequently traded, we derived the acquisition price of BEN_OTA obligation FTRs from the price difference between BEN_OTA and OTA_BEN option FTRs—averaged over all FTR periods traded within each month. Prices for primary and variation auctions occurring within each month are averaged to give a smoother curve.

10.37 The black curve is the difference between the blue and orange curves, ie, the "premium" paid to acquire the actual FTR over the synthetic equivalent. The dashed black line is the average value of this "premium" over the history of the FTR market.

10.38 While this "premium" is sometimes positive and sometimes negative, it does appear to be slightly positive on average. However, it is possible this is just an artefact of the FTR auction arrangements. The futures are quarterly products with a horizon of up to four years whereas FTRs are monthly products with a horizon of only two years.

10.39 Furthermore, all futures products out to the horizon can be traded on any business day, whereas only a maximum of six FTR periods is available at each auction.[17] And these arrangements have changed over time: in the earliest months of the FTR market only close-in periods were auctioned. This was gradually extended until the two-year horizon was reached in July 2014. There was a further change in April 2017 when the number of periods auctioned in each primary auction was increased from three to six.[18] The average prices for auctions more heavily weighted towards close in periods are likely to be more sensitive to current spot market conditions.

Speculators likely to increase FTR liquidity

10.40 Certain FTR products sometimes trade in auctions at prices far higher than they eventually settle at.

10.41 This enables astute traders to make significant profits from time to time, which may lead to accusations that the FTR market merely exists as a money-making scheme for speculators who have no presence in the physical electricity market.

10.42 But in fact, such trading activity serves a market making role, likely increasing the liquidity of the FTR market, since it increases the likelihood that physical participants will be able to adjust their FTR holdings at a reasonable price as their circumstances change.

Spring washer effect can cause high FTR auction prices

10.43 In the spot market, the so-called spring washer effect can cause nodal prices on the downstream side of a binding transmission constraint many times higher than the marginal generation offer.

10.44 A similar mechanism can occur in FTR auctions, whereby the "clearing price" of an FTR across a binding transmission constraint can be many times higher than the marginal FTR bid.

10.45 A key difference is that in the spot market, prices are related to physical electricity flows, whereas in FTR auctions prices relate to the flows implied by cleared FTR bids.

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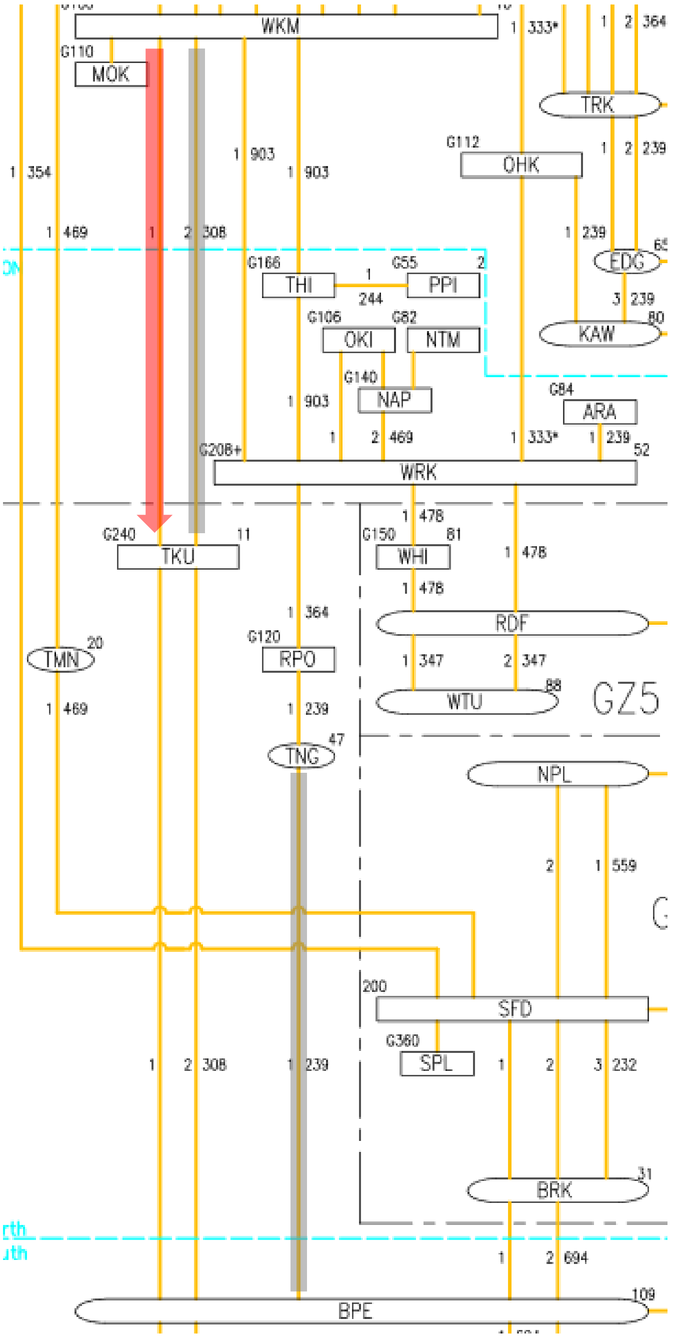
16 www.emi.ea.govt.nz/r/xpryo

17 Any FTR products can also be traded on the secondary market at any time, but the number of secondary trades has been very small.

18 There are two auctions every month. The first is called the primary auction. The second, the variation auction, has auctioned six FTR periods ever since steady state was reached in January 2014.

10.46 Because the direction of physical flows is often unknown in advance and because flow direction can vary between trading periods within a month, traders typically bid for option FTRs in both directions in order to cover both possibilities. Furthermore, the full auction capacity is invariably purchased in both directions, even though physical flows may be significantly less and may be in only one direction.

Figure 10: Outages and constraints for January 2019 FTR period



Source: Electricity Authority

Notes:
1. Grey rectangles indicate outages
2. Pink arrow indicates binding constraint

10.47 For these reasons, the implied auction flows can be very different to typical physical flows, and the resulting FTR auction prices can also be quite different to the usual price differentials that occur in the spot market.

10.48 An example of this phenomenon occurred in the 20 December 2018 auction for the January 2019 FTR period. In this particular FTR period there were outages of the BPE_TNG_1 and TKU_WKM_2 circuits in the central North Island which caused a binding constraint (in the auction) for southward flow on the TKU_WKM_1 circuit in the base case, ie, no contingency (see Figure 10).

10.49 FTRs purchased in the 20 December 2018 auction for the January 2019 FTR period included the following (final settlement price included for comparison):

Table 6: Results of 20 December 2018 auction for January 2019 FTR period

FTR Product	Auction Price ($/MWh)	Settlement Price ($/MWh)
WKM_OTA Obligation	$5.20	$6.48
WKM_OTA Option	$5.36	$6.48
HAY_WKM Obligation	-$82.27	$3.13
HAY_WKM Option	$7.49	$3.72

Source: Electricity Authority

10.50 Note that in most cases the auction price and settlement price were in the same order of magnitude. However, for the HAY_WKM obligation the absolute value of the auction price was 26 times the settlement price. The negative sign means that the “purchaser” was effectively paid $82.27/MWh to take on this FTR and then at settlement received an additional $3.13 for a total profit of $85.40/MWh.

10.51 From the known relationships between obligation and option prices, we can also deduce the following implied shadow prices for FTRs that were not purchased in the auction:[19]

Table 7: Implied prices of 20 December 2018 auction for January 2019 FTR period

FTR Product	Auction Price ($/MWh)	Settlement Price ($/MWh)
OTA_HAY Obligation	$77.07	-$9.61
HAY_OTA Obligation	-$77.07	$9.61
OTA_WKM Option	$0.16	$0.00
WKM_HAY Option	$89.76	$3.59

[19] FTR price identities:
A_B Obligation price = A_B Option price - B_A Option price
A_C Obligation price = A_B Obligation price + B_C Obligation price
A_B Obligation price = -B_A Obligation price

FTR Product	Auction Price ($/MWh)	Settlement Price ($/MWh)
WKM_HAY Obligation	$82.27	-$3.13

Source: Electricity Authority

10.52 Note the high implied auction prices for FTRs that cross the binding TKU_WKM_1 constraint in a southward direction (or large negative price for northward obligations).

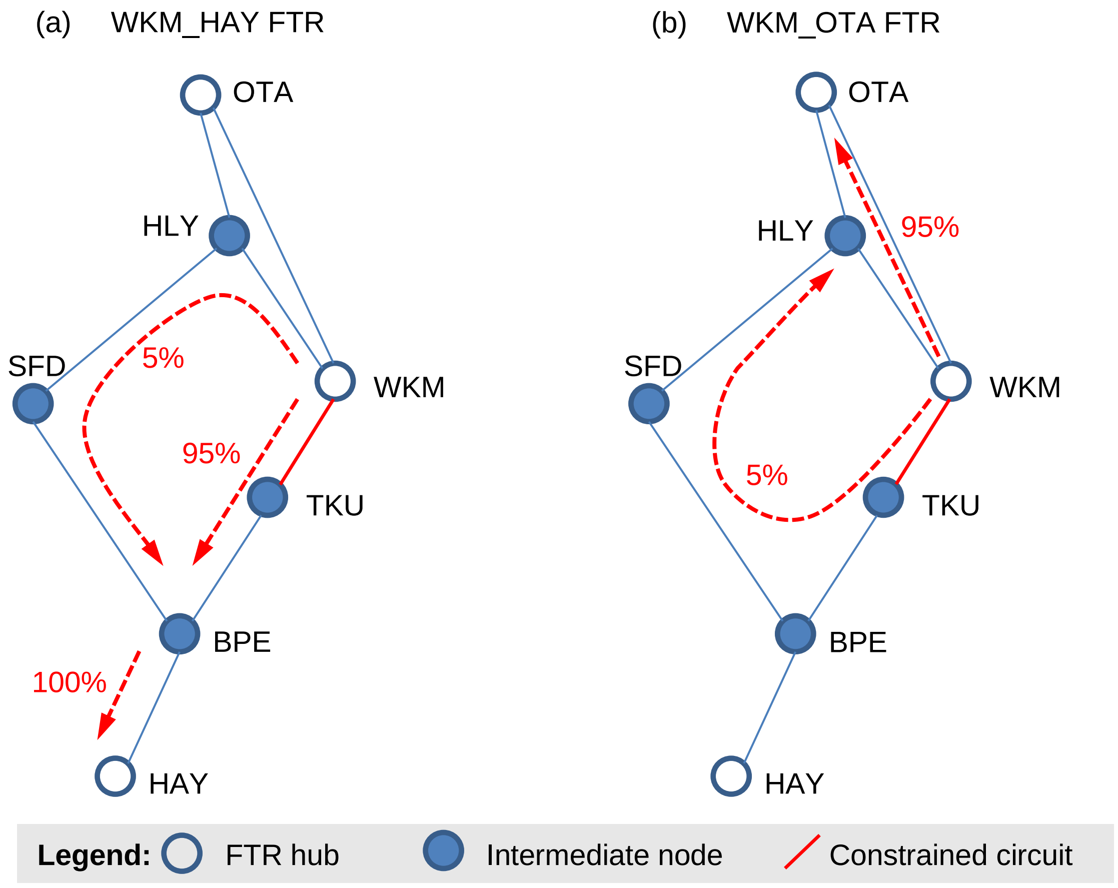
10.53 Bid prices are not publicly disclosed. However, we can assume the price that the purchaser bid for the HAY_WKM obligation was in the vicinity of the settlement price—perhaps a little lower—ie, around $3 or slightly less. Since the clearing price of -$82.27 was less than the bid price the bid cleared.

10.54 The -$82.27 clearing price is due to the spring washer effect. It works like this:

(a) For every MW flowing from WKM to HAY, most of it takes the direct route through the constrained TKU_WKM_1 circuit and on down through BPE to HAY, while a small fraction takes the indirect route up to OTA and HLY and back down through SFD to BPE and HAY (Figure 11(a)).

(b) For every MW flowing from WKM to OTA, again most of it takes the direct route while only a small fraction takes the indirect route down through TKU_WKM_1 to BPE and back up to OTA via SFD and HLY (Figure 11(b).

Figure 11: Implied flows for WKM_HAY and WKM_OTA FTRs



Source: Electricity Authority

Notes: 1. Percentage flows are illustrative only

10.55 Thus, both WKM_OTA and WKM_HAY FTRs are competing for the limited TKU_WKM_1 capacity. But WKM_HAY FTRs have a much greater impact on flows through the constrained circuit. Consequently, the constraint has a much greater effect on the price of WKM_HAY FTRs than on WKM_OTA FTRs.

10.56 Or to look at it another way, to free up capacity to satisfy the demand for WKM_OTA FTRs, WKM_HAY FTRs only have to reduce by a relatively small amount. This makes a reduction in WKM_HAY FTRs (or an increase in HAY_WKM obligations since they provide counter-flow) very valuable to the market.

10.57 The ratio of the option shadow prices (89.76/5.36) is 16.7.[20] This implies that every MW reduction in WKM_HAY FTRs frees up 16.7 MW of capacity for WKM_OTA FTRs.[21] In effect the purchasers of WKM_OTA FTRs are paying the purchaser of the HAY_WKM obligation for freeing up capacity.

20 It's more complicated for obligation FTRs because their prices are a function of constraints, and hence demand for FTRs, in both directions.

21 The illustrative percentages in Figure 11 correspond to a ratio of 19 (95% / 5%) rather than 16.7.

10.58 A similar situation occurred in the 22 November 2018 auction for the same FTR period, where HAY_WKM obligations were purchased at -$95.28.

10.59 We can also conclude from data in the FTR register that a number of FTRs purchased in earlier auctions were sold back for a high price—likely into one or both of these auctions. From the recorded Acquisition Cost, Original Acquisition Cost, MW and Price we can deduce the original MW purchased, total MW resold and the resale price (see Table 8).[22]

Table 8: Resold FTRs for January 2019 FTR period

FTR Product	Date Acquired	Purchase Price ($/MWh)	Resale Price ($/MWh)[22]	Settlement Price ($/MWh)
OTA_BEN Options	19/01/2017	$0.35	$85.03	$0.59
OTA_HAY Options	19/01/2017	$0.14	$84.40	$0.04
OTA_HAY Options	19/01/2017	$0.14	$76.32	$0.04
OTA_HAY Options	16/02/2017	$0.10	$83.29	$0.04
OTA_INV Options	16/03/2017	$2.59	$90.70	$1.23
WKM_HAY Options	17/05/2018	$1.81	$100.38	$0.59

Source: Electricity Authority

10.60 Again, note that all these FTRs imply southward flow through the central North Island and sold for prices comparable with the 22 November 2018 and 20 December 2018 auction prices—again orders of magnitude higher than the original purchase price and final settlement price. Again, the sellers of these FTRs in Table 8 are effectively being paid by purchasers of WKM_OTA FTRs for freeing up capacity.

10.61 The point of all this is that the price traders can receive for freeing up capacity, either by selling forward-direction FTRs or buying reverse-direction obligations, is often determined by demand for FTRs on different but related paths.

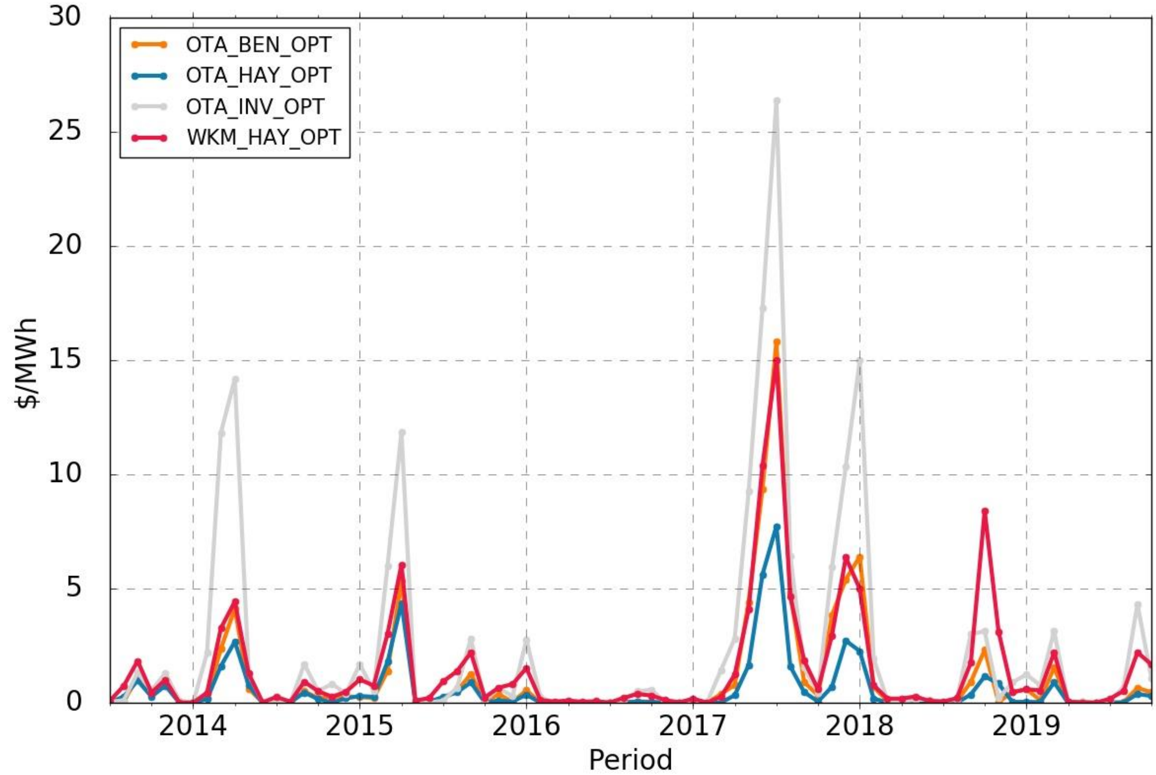
10.62 And while the prices of these related FTRs may be very different, the money balances—one trader receiving a high price for a small volume of FTRs and the other trader paying a low (normal) price for a large volume of FTRs.

10.63 And this activity likely enhances liquidity, because extra FTRs can often be made available to help to satisfy demand. The auction always maximises the value of cleared bids. Thus, limited grid capacity is allocated to those FTR purchasers who value it most highly.

10.64 One might ask if the parties who resold southward-going FTRs as listed in Table 8 are simply gaming the system—using up valuable grid capacity in the hope of making a quick profit if the opportunity arises. But these are all legitimate hedge products in their own right. During dry hydro conditions when electricity flows tend to reverse, such southward FTRs can settle at much higher values (Figure 12).

22 Weighted average price if resold over more than one auction.

Figure 12: Settlement prices of southward-going FTRs



Source: Electricity Authority

Notes: 1. Prices for months prior to the relevant hubs being added to the FTR regime have been inferred from the nodal prices.

11 Other Interactions with TPM project

Allocation of residual LCE

11.1 The TPM proposals include an option to allocate the LCE (including residual LCE[23]) generated by each transmission investment to customers in proportion to the transmission charges they pay in respect of that investment.[24]

11.2 The FTR market has the effect of extracting much of the hedging property from this LCE stream. In fact, because auction revenue is used to support FTR settlements, a greater quantity of FTRs is allocated than could be supported by the LCE alone. This extracts even more hedging property leaving the residual LCE negatively correlated with nodal prices, ie, a sort of anti-hedge.

11.3 Nevertheless, averaged over time these payments should still support the efficiency intentions of this TPM option.[25]

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[23] The residual LCE is the proceeds remaining after settling the FTR market. The residual LCE would be allocated in the same proportions as the LCE.

[24] At present this approach is only used for connection assets and the HVDC. LCE (including residual LCE) from interconnection assets is also allocated in proportion to the charges for these assets. However, rather than being allocated on an investment by investment basis, these charges (and hence LCE) are currently “postage-stamped” according to each customer’s share of RCPD.

[25] 2019 issues paper Transmission pricing review, Appendix F, paragraph F.5 through F.23

Appendix A Perceptions of Financial Transmission Rights — Research Report

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Glossary of abbreviations and terms

Act	**Electricity Industry Act 2010**
ASX	**Australian Securities Exchange**
Authority	**Electricity Authority**
BEN	**Benmore**
CBA	**cost benefit analysis**
CFD	**contract for difference (a type of hedge contract)**
Code	**Electricity Industry Participation Code**
Commission	**Electricity Commission**
FAP	**FTR allocation plan**
FPFV	**fixed price fixed volume (a type of hedge contract)**
FPVV	**fixed price variable volume (a type of hedge contract)**
FTR	**financial transmission rights**
HAY	**Haywards**
INV	**Invercargill**
ISL	**Islington**
KIK	**Kikiwa**
LPR	**locational price risk**
NMIR	**national market for Instantaneous reserves**
OTA	**Otahuhu**
RDF	**Redclyffe**
RTP	**real-time pricing**
SPD	**scheduling, pricing and dispatch (the market clearing engine)**
TPM	**transmission pricing methodology**
VAS	**virtual asset swaps**
WKM	**Whakamaru**