Financial Transmission Rights market observations

Ensuring arrangements are fit-for-purpose

Issues paper

Submissions close: 5pm, Monday 04 July 2022

24 May 2022

Foreword

The Electricity Authority (Authority) established a financial transmission rights (FTR) market in 2013. FTRs were designed to assist wholesale electricity market participants to manage locational price risk (LPR). This in turn was expected to benefit consumers by enabling greater competition in wholesale and retail markets.

Periodic reviews of the FTR market policy settings, including its funding arrangements via the and Loss and Constraints Excess (LCE), are required to ensure the FTR market promotes competition in the electricity industry for the long-term benefit of consumers – in accordance with the first limb of Authority's statutory objective. This FTR review continues the work on the Hedge Market Enhancements project, which focussed on delivering enduring market-making services that are fit for purpose, including by way of aligning costs with beneficiaries.

New Zealand's transition to a low carbon future requires fit for purpose risk markets that deliver maximum benefit to consumers. The Authority's recently published *Energy Transition Roadmap* sets out the steps the Authority is taking to support an efficient transition to a low-emissions energy system, including risk management through the transition, and the recent work of the Authority's *Market Development Advisory Group* to consider generation investment and reliability under 100% renewable electricity. This FTR review will assist the Authority in its strategic focus on efficient risk markets to support the transition to a low carbon future.

This paper sets out the Authority's observations and concerns about the operation of the FTR market, some of which appear to warrant further investigation. The Authority seeks stakeholder engagement and feedback on these initial observations to help the Authority to define any issues that require further consideration.

James Stevenson-Wallace

Chief Executive

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What you need to know to make a submission

Purpose of this document

1.1 The Authority, as part of its strategic focus on efficient risk markets, has identified a set of initial observations from its review of the current Financial Transmission Rights (FTR) market and Loss and Constraint Excess (LCE) allocation policy settings.

1.2 The purpose of this document is to seek feedback on the Authority's initial observations, and to receive feedback from stakeholders on the current FTR market and LCE allocation policy settings to ensure any issues or opportunities are robustly defined. This will assist in ensuring any potential intervention is aligned with the long-term benefit of consumers.

How to make a submission

1.3 The Authority's preference is to receive submissions in electronic format (Microsoft Word or PDF). Submissions in electronic form should be emailed to WholesaleConsultation@ea.govt.nz with 'Financial Transmission Rights market review' in the subject line.

1.4 If you cannot send your submission electronically, please contact the Authority (WholesaleConsultation@ea.govt.nz or 04 460 8860) to discuss alternative arrangements.

1.5 Please note the Authority intends to publish all submissions it receives. If you consider that the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published,

(b) explain why you consider that part should not be published, and

(c) provide a version of your submission that can be published (if the Authority agrees not to publish your full submission).

1.6 If you indicate there is part of your submission that should not be published, the Authority will discuss with you before deciding whether to publish that part of your submission.

1.7 However, please note that all submissions received, including any parts that are not published, can be requested under the Official Information Act 1982. This means the Authority would be required to release material that was not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material that you said should not be published.

When to make a submission

1.8 Please deliver your submission by **5pm** on **Monday 04 July 2022**.

1.9 The Authority will acknowledge receipt of all submissions electronically. Please contact WholesaleConsultation@ea.govt.nz or 04 460 8860 if you do not receive electronic acknowledgement of your submission within two business days.

Further information

1.10 The Authority's website contains useful background material about its previous work, the work of its advisory groups, and the work of its predecessor (the Electricity Commission) relating to the FTR market and LCE allocations: https://www.ea.govt.nz/about-us/what-we-do/our-history/archive/dev-archive/work-programmes/market-wholesale-and-retail-work/ftr-development/

1.11 In November 2019 a post-implementation review was completed on the effectiveness of the FTR market where participants were interviewed about their use of the FTR market. The findings from those interviews can be found here: https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2019-2020/post-implementation-review-of-the-ftr-market/

1.12 Please direct any specific questions or queries to: WholesaleConsultation@ea.govt.nz

Introduction

2.1 Financial transmission rights (FTRs) were introduced in 2013 to help manage locational price risk (LPR), enhance retail and generation competition, and provide long-term consumer benefit in line with the Authority's statutory objective. Since its inception, concerns raised by market participants and observations by the Authority suggest the FTR market may not be addressing the problems it was created to solve.

2.2 This paper considers issues and opportunities to improve the current policy settings for the FTR market and the allocation of loss and constraint excess (LCE). As part of this review, the Authority seeks views from market participants and other stakeholders on the existing FTR market and LCE allocation policy settings with a particular focus on the effectiveness of the FTR market in managing LPR for market participants.

2.3 This paper sets out the Authority's observations on LPR and the current FTR and LCE policy settings. These observations raise some concerns FTRs are not effective at addressing the problems they were created to solve, and consequently are not aligned with the Authority's statutory objective:

(a) the FTR market is not tightly targeted at the problem – FTRs were created to manage risk, but FTRs payout on nodal price differences due to both constraints and losses even though losses are relatively predictable,

(b) the link between FTRs and the intended improvement in retail and generation competition appears to be limited,

(c) many parties (particularly direct connect consumers and independent retailers) who are subject to LPR are not using the FTR market to manage LPR and are choosing to manage LPR in other ways, despite other market solutions for managing LPR being limited, and

(d) non-physical financial parties appear to be profiting from the FTR market and the link to consumer benefit is unclear.

2.4 The Authority is considering FTR and LCE policy settings now because:

(a) the Authority has a strategic focus on efficient risk markets to support the transition to a greater share of renewable generation. The Authority considers it is important that participants have access to effective tools to manage LPR,

(b) the Authority needs to consider the methodology Transpower uses to rebate LCE as part of proposed transmission pricing methodology (TPM) changes,

(c) FTRs have consumed a greater share of available LCE recently, from an average of 13% of total LCE per month under two FTR hubs, 17% of total LCE per month under five FTR hubs to an average of 47% of total LCE per month under eight FTR hubs. The current eight FTR hubs consume approximately $60 to $70 million per year from LCE. There may be alternative uses for the LCE that provide greater benefit for consumers that better align with the Authority's statutory objective.

2.5 This consultation is linked to a previous consultation paper on the LCE rebate methodology governance, principles, and pass-through because the methodology ultimately chosen for rebating LCE may provide a partial LPR hedge for transmission customers. The LCE rebate methodology consultation paper, also known as the settlement residual allocation methodology (SRAM) is available here:

https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/settlement-residual-allocation-methodology-sram/consultation/#c19104 .

2.6 This paper seeks feedback on the Authority's observations of the FTR market and LCE allocations to gather further information from stakeholders to ensure any problems or opportunities are robustly defined. A robust problem or opportunity definition will allow interventions (if any) to provide maximum benefit to consumers. After considering stakeholder feedback and any further analysis on the observations in this paper, the Authority will decide whether there are challenges or opportunities of sufficient materiality to proceed with its review.

FTRs were introduced in 2013 to help manage locational price risk

3.1 Sources of electricity generation are often far 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 an event, referred to as 'instantaneous reserves').

3.2 These factors can result in large and unpredictable price differences across the electricity grid resulting in LPR. LPR affects generators and purchasers, and its presence, without a management tool, could lead to lower levels of competition in wholesale and retail electricity markets.

3.3 Therefore, one of the recommendations from 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]

3.4 This recommendation was captured in Section 42 of the Electricity Industry Act 2010 and was required to be reflected in the Code within 12 months of the Authority being established in 2010. The focus of the recommendation however was broadened from retail to all wholesale market participants:

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

The Authority subsequently introduced the FTR market in 2013, with the first FTR auction in June 2013.FTRs are a risk product designed to manage LPR

3.5 FTRs are a type of locational risk product covering the price difference between pairs of grid nodes (called hubs).

3.6 Participants can manage LPR by purchasing FTRs at an auction. An FTR pays its owner the difference in spot price between two nodes on the transmission network. Unlike traditional hedge products which have a 'buyer' and a 'seller,' FTRs only require a buyer. In this case, the seller is the FTR manager, who does not take a financial risk in operating the sale of FTRs.

3.7 Similar to Contracts for Differences (CFDs), FTRs are purely financial arrangements and do not involve the physical delivery of electricity, this means the FTR market may also attract participants who do not trade physical electricity.

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1 Ministry of Business, Innovation and Employment, *Improving electricity market participants: summary notes on recommendations taking account of submissions.* Available here: Wayback Machine (archive.org)

2 Paragraph 3.1, Electricity Authority, *Post implementation review of the FTR market*. Available here: Long-form report (ea.govt.nz)

3.8 Hedge contracts are traditionally transacted between a buyer and a seller (occasionally involving a third party). With the FTR market, the FTR manager allocates FTRs to FTR participants via an auction process and there is no counter party. The FTR auction process is voluntary to participate in, and participation is not limited to participants who are subject to LPR.

FTRs are funded by auction revenue and the Loss and Constraint Excess (LCE)

3.9 FTR payments are funded first by using the revenue generated from the auction of FTRs (ie, money paid by participants purchasing FTRs) and, if the FTR auction income does not fully cover FTR payments, then allocated LCE (also known as FTR rentals) is used to cover the shortfall. Historically, 30% of payments to FTR holders has come from LCE and 70% from auction revenue.

3.10 LCE is the surplus collected from the wholesale electricity spot market once payment is collected from buyers and generators are paid for their supply of generation. LCE exists because there are price differences between grid nodes from transmission losses and grid constraints.

3.11 Any LCE funds not required to fund FTRs are provided to the grid owner (Transpower) who allocates[3] the funds to transmission customers.[4] If FTR auction revenue and the LCE are not adequate to fund the FTR payments, the FTR payments are scaled to the level of FTR auction revenue and LCE available.[5]

3.12 When auction income and FTR rentals are adequate to settle the FTR market this is referred to as revenue adequate, and when it is insufficient this is referred to as revenue inadequate. When revenue is inadequate scaling of FTR payouts are required.

3.13 A summary of the payments made to FTR participants and transmission customers for 2020 and 2021 is provided below in Table 1.

3.14 FTR participants can be physical participants or non-physical participants. Physical participants are ones which generate or consume electricity and are looking to hedge operational risks associated with their business. Non-physical participants are financial entities that are purely interested in trading electricity products for a profit. Physical participants may also engage in trading for profit.

3.15 Figure 1 below, shows the cash flows within the FTR market. Each month LCE is calculated. That amount is then subject to a calculation based on Schedule 14.6 of the Electricity Industry Participation Code (the Code) that determines what proportion is available to settle the FTR market (FTR rentals). The full allocation of FTR rentals is not always required to settle the FTR market, with the balance (residual LCE) returned to transmission customers.

3.16 Non-FTR rentals are the portion of LCE that are allocated to transmission customers.

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3 For more details on the allocation of LCE to transmission customers please refer to the Settlement Residual Allocation Methodology (SRAM) consultation - [Consultation — Electricity Authority (ea.govt.nz)]

4 Transmission customers are typically generators, distributors and large industrial companies that are directly connected to the grid. These customers pay transmission charges to Transpower, the grid owner for use of the electricity transmission grid. LCE funds from the electricity transmission grid are ultimately borne as a cost to transmission customers.

5 The FTR market is designed so that, on average, one in every 12 months would experience revenue inadequacy. In the eight years since the FTR market started there have only been two months when there was FTR “revenue inadequacy” leading to the scaling of FTR payments.

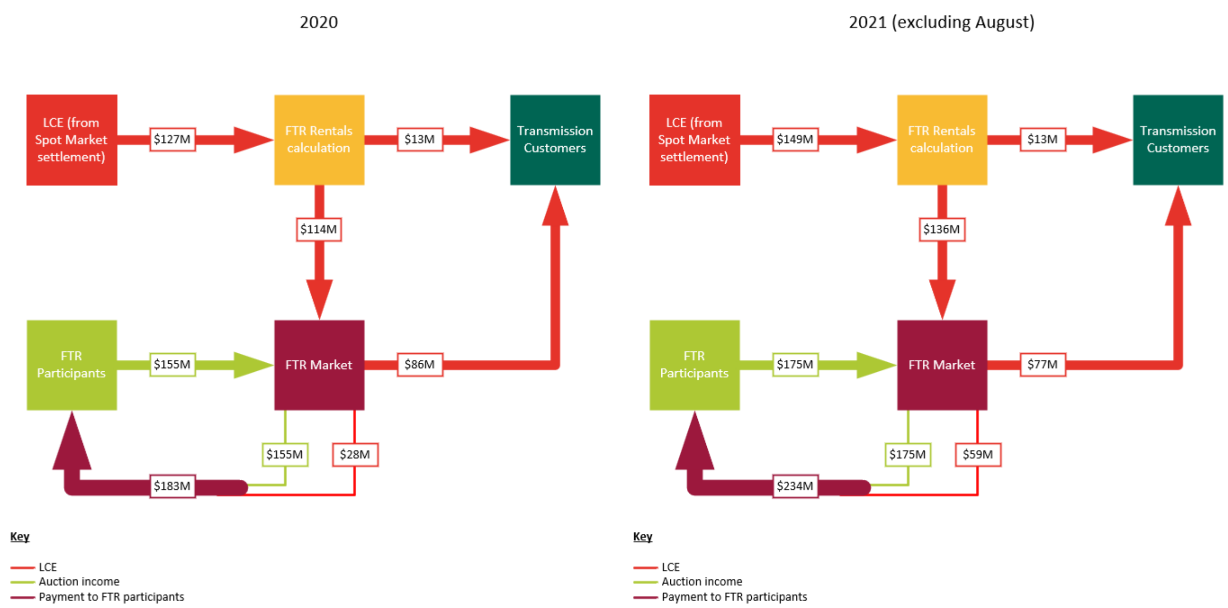
Table 1 Summary of payments to FTR participants and transmission customers (2020 and 2021)

	FTR participants		**Transmission customers**	
	Auction Income	**FTR Rentals**	**Non-FTR Rentals**	**Residual LCE**
2020	$155 million	$28 million	$13 million	$86 million
	Total - $183 million		Total - $99 million	
2021	$175 million	$59 million	$13 million	$77 million
	Total - $234 million		Total - $90 million	

3.17 In 2020 and 2021 there were three months where auction income exceeded FTR payments, hence FTR rentals were not required. However, August 2021 is yet to be settled due to the 9 August 2021 event,[6] resulting in delays for interim prices becoming final.

3.18 The full FTR cashflows for 2020 and 2021 are detailed below in Figure 1.

Figure 1 FTR cashflows for 2020 and 2021 (excluding August 2021)



6 Reference: https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2021/electricity-authority-review-of-9-august-2021-event-under-the-electricity-industry-act-2010/

Analysis of potential August 2021 settlement and LCE consumption cashflows using July 2021 power flow data and interim prices for trading periods yet to be finalised, indicate the month is likely to be revenue adequate. However, this will not be finalised until the trading periods held as interim are made final.

FTR market design aims to maximise LCE use for settling FTRs

3.19 The decision to use a combination of auction revenue and LCE was justified on the basis it would increase revenue adequacy,[7] which in turn would help to ensure FTRs are a reliable tool for managing LPR.[8]

3.20 A noted trade-off with this decision was that auction revenue would not be available to fully offset the impact on transmission customers who would not receive LCE. However, because this outcome was considered to be a wealth transfer, the Authority at that time (28 April 2011), did not consider there to be negative efficiency effects.[9]

3.21 The FTR allocation plan sets the Revenue Adequacy Objective as:

(a) the primary objective is for Revenue Inadequacy to occur one month in twelve

(b) the secondary objective is for the annual average scaling factor to be 98%.

3.22 These objectives assist the FTR Manager, who is responsible for developing the FTR policy on the FTR grid, to achieve a balance between ensuring sufficient revenue is available to settle FTRs and a sufficient volume of FTRs are available for purchase.[10]

The Authority investigated several options for managing LPR before deciding to pursue FTRs

3.23 A range of alternative solutions for managing LPR were considered by the Authority and its predecessor the Electricity Commission (Commission), before FTRs were implemented. These solutions included:

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

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

(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, or

(e) various combinations of the above.

Options for managing LPR in 2009 were limited

3.24 In 2009, the Commission considered most of the existing options for managing LPR were generally high cost and resulted in either less competition or reduced economic activity. Other options (such as purchasing hedges at central nodes) were ineffective at that time. The options considered before the introduction of FTRs are set out in Table 2 below.

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7 Revenue adequacy is when the FTR settlement amount (funding for FTRs) is sufficient to settle all FTR Hedge Values in full for a particular FTR period.

8 Paragraph 3.4.137, Electricity Authority, *Consultation Paper: Managing locational price risk: Proposed amendments to Code.* Available here: Consultation Paper (ea.govt.nz)

9 Paragraph 3.4.137, Electricity Authority, *Consultation Paper: Managing locational price risk: Proposed amendments to Code.* Available here: Consultation Paper (ea.govt.nz)

10 Section 4.8, Financial Transmission Rights, *FTR Allocation Plan 2018.* Available here: FTR_Allocation_Plan_2018 (2).pdf

Table 2 Existing options for managing LPR in 2009[11]

Option	Feasible for retailer	Feasible for large industrial purchasers	Economic activity
Purchase hedge at central node	Yes	Yes	Does not offset high locational prices.
Purchase hedge at local node	Yes	Yes	Hedge unlikely to cover all load, generators likely to be very reluctant to sell hedges unless they are local (so hedges will only cover local generation), hedge price is likely to be high because of lack of other options.
Cut load	Limited	Yes, but typically only for a small proportion of load	Less production, consumption.
Increase price	Yes	No (in relation to electricity)	Increased electricity cost, less production, consumption.
Build generation	Yes	Yes	High cost but increased generator competition.
Exit market	Yes	Yes	Less competition, production, consumption.
Do no enter market	Yes	Yes	Less competition.
Sell at spot prices to end users	Yes, to a degree	N/A for some	End users will become more exposed to LPR, which they may be able to respond to by cutting load, reducing consumption.

3.25 The Commission noted that the ability of purchasers to buy a competitively priced hedge at their node to cover their LPR was likely to be limited because of the low level of liquidity in the New Zealand hedge market. At the time, energyHedge[12] (a voluntary CFD exchange) accounted for less than 0.01% of the volume of electricity sold on the spot market in New Zealand. Also, the Australian Securities Exchange (ASX) only listed

11 Table 2, Electricity Commission, *Consultation paper: Managing locational price risk: Options, November 2009.* Available here: 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/#c8182.

12 energyHedge was a company formed by Contact Energy, Genesis Power, Merdian Energy, Mighty River Power and Trustpower in 2010, which seeked to enter bi-lateral market-making agreements with the ASX

futures and options for two New Zealand nodes (Otahuhu and Benmore) with a very small number of hedges traded.[13]

Historically it has been more difficult for participants to manage constraint LPR than loss LPR

3.26 Analysis of loss and constraint rentals over January 2008 – April 2010 showed that:

(a) transmission constraint rentals and reserve constraint[14] rentals were significantly more volatile in relative terms than loss rentals, and

(b) loss rentals were more correlated with energy prices than constraint rentals (when energy prices were higher so were loss costs)—the correlation of loss rentals with total load revenue was 97%, while for transmission constraint rentals it was 40%, and for reserve constraint rentals it was 18%.[15]

3.27 The development of the FTR market was originally established to manage price separation due to congestion. The decision to have FTRs cover price effects due to both congestion and losses was following the recognition that variability in hydrology also resulted in price volatility.

3.28 While energy hedging could have been used to manage most of the risk associated with losses (if there was a sufficient volume of energy hedges available), energy hedging would not have been an effective tool for managing LPR associated with reserves and transmission constraints. Inter-island LPR (between the North and South Islands) was a bigger problem than intra-island LPR (within either the North or the South Island).

3.29 The Commission undertook detailed empirical analysis of LPR in 2010. This analysis identified that, even once the HVDC Pole 3 was commissioned,[16] the capacity of the HVDC link was expected to be a permanent consideration for LPR management. The Commission also noted that although transmission grid investment within each of the two Islands may, over time, change the magnitude of intra-Island LPR, it was expected to continue to be low relative to inter-island LPR.[17]

3.30 The Commission found that on average inter-island constraint rentals were about 80% of total constraint rentals between January 2008 and April 2010, while intra-island constraint rentals made up the remaining 20%. In addition, for all but four months of the sample period, inter-island constraint rentals accounted for at least 60% of total constraint rentals.[18]

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13 Paragraph 3.1.13, Electricity Commission, *Consultation paper: Managing locational price risk: Options, November 2009*. Available here: 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/#c8182.

14 A constraint resulting from instantaneous reserve requirements that causes price separation between nodes, such as the HVDC terminals.

15 Paragraphs 4.3.9 and 4.3.14, Electricity Commission, *Consultation Paper: Managing locational price risk proposal, September 2010.* Available here: 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/#c8177

16 HVDC Pole 3 was commissioned in May 2013 and allowed the HVDC link to operate at a greater capacity.

17 Paragraphs 3.4.6-3.4.7, Electricity Commission, *Consultation Paper: Managing locational price risk proposal, September 2010.* Available here: 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/#c8177.

18 Paragraphs 5.5.3-5.5.4, Electricity Commission, *Consultation Paper: Managing locational price risk proposal, September 2010.* Available here: 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/#c8177.

3.31 Further analysis in 2011 found that 67% of all modelled constraints out to 2025/26 would be caused by either the HVDC or the Bunnythorpe-Haywards equation constraint[19], which would be partially covered by an inter-island FTR.[20] Any cover for LPR would be limited to the extent that the price separation could be managed by a FTR between Benmore and Haywards. However, no FTR was available to cover the price separation between Haywards and Otahuhu. The addition of obtaining Benmore and Otahuhu futures products to create a synthetic FTR may provide additional cover.

3.32 However, some industry participants considered that an inter-island solution to LPR was not required because coverage of inter-island LPR could be obtained through hedge market swaps (between Otahuhu and Benmore).[21] While the Authority agreed that participants may be able to manage some of their LPR through hedge market swaps, it noted that there wasn't an active swap market (in 2011) so it was unlikely that a participant would be able to obtain enough swaps to cover all of their LPR.

LPR was impacting retail competition, but other impacts were not considered

3.33 In 2010, the Commission considered the relationship between location of generation and retailing presence for the five major generator retailers. The analysis indicated that for four of the five major generator retailers, there was a strong correlation between high nodal price exposure and low relative regional market share. The Commission's analysis is illustrated in Figure 2 below.[22]

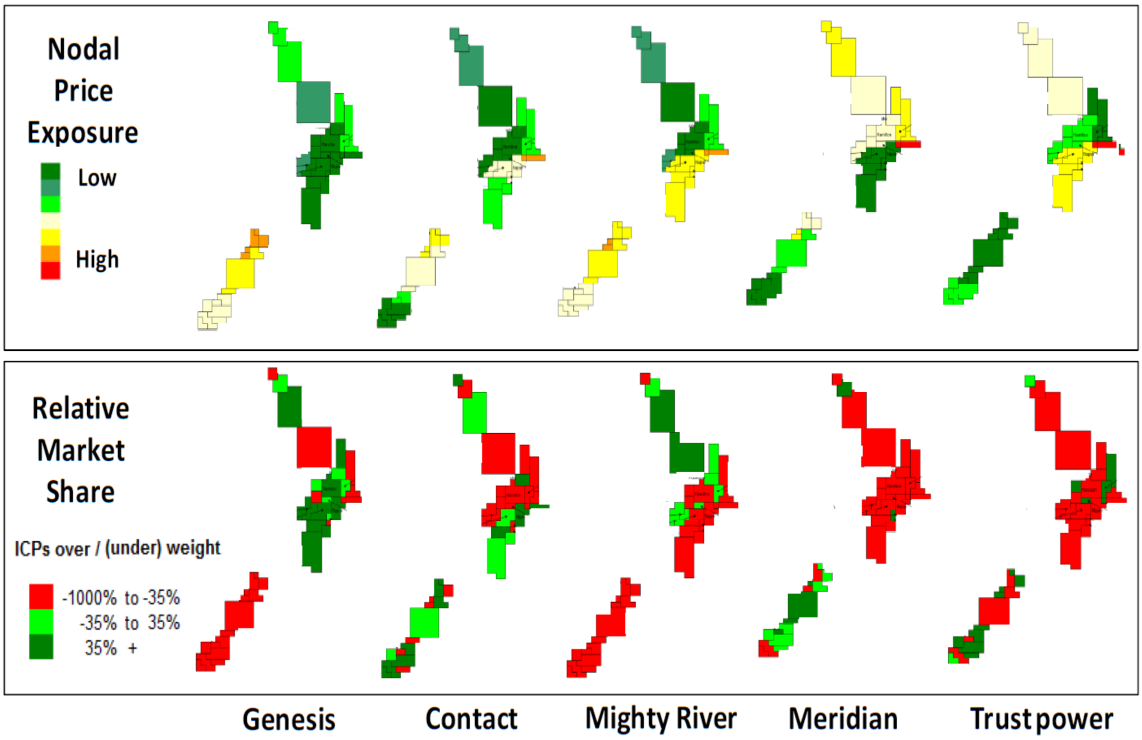
19 In 2017 the impact of Bunnythorpe-Haywards constraint has been significantly reduced due to the reconductoring of lines A and B in 2017 which increased capacity on the transmission circuit, reducing the incidence of constraints and price separation.

20 Paragraph 3.3.18, Electricity Authority, *Consultation Paper: Managing locational price risk: Proposed amendments to Code, April 2011.* Available here: 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.

21 Paragraph 3.3.1, Electricity Authority, *Consultation Paper: Managing locational price risk: Proposed amendments to Code, April 2011.* Available here: 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.

22 The analysis that the Commission considered was initially prepared for the Commission's Market Design Review in 2008 (https://www.ea.govt.nz/about-us/what-we-do/our-history/archive/dev-archive/consultations/wholesale-consultations/2008/archive-market-design-review-options-paper-2008/) and related to the period 2003-2007. However, the Commission considered that the analysis was still relevant because the influence of generator location on competition was enduring and was a factor in the Ministerial Review considering that the SOE physical and virtual asset swaps were necessary.

Figure 2 Correlation between nodal price exposure and relative market share (2003-2007)[23]



3.34 Figure 2 shows, for example, that Genesis' market share in the South Island was significantly lower than its national average market share, coinciding with its higher nodal price exposure in the South Island than the North Island.

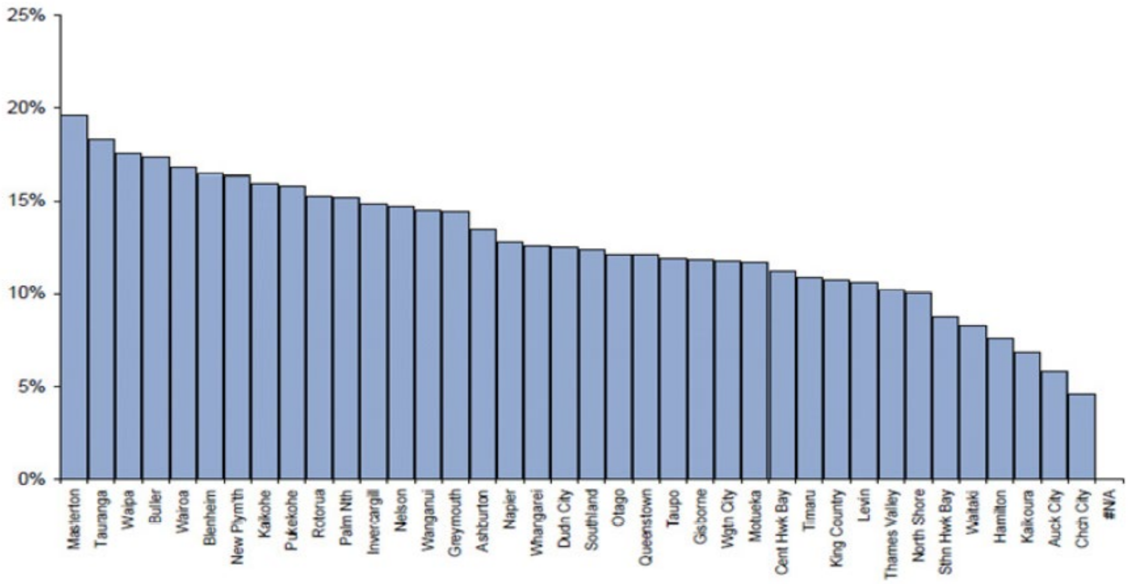
3.35 Contact was the only generator retailer of the five that was assessed to not have a strong correlation between high nodal price exposure and regional market share as it had generation relatively evenly distributed throughout the country.

3.36 The Commission considered that the regional market share differences between the major generator retailers was a strong indicator that the lack of suitable LPR management tools at the time was an impediment to more robust retail competition. If it was difficult for the large generator retailers to manage LPR, the Commission considered it was likely to be even more difficult for small prospective new entrant retailers.

3.37 The Commission also considered the retail margins for the dominant retailer in each region (line company network areas). It found that in 2007-08 there was evidence that the estimated incumbent retail margin for medium-use residential customers was high in a number of regions (such as Masterton, Buller, Wairoa and Blenheim) where LPR was more prevalent. This is shown in Figure 3 below.

[23] Figure 9, Electricity Commission, *Consultation Paper: Managing locational price risk proposal, September 2010.* Available here: 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/#c8177.

Figure 3 Estimated incumbent margin for medium-usage residential customers in 2007-08[24]



3.38 The Commission did not present any evidence that LPR was having an impact on generator and direct connect customer decisions.

LPR will evolve over the next decade

Observation 1: Changes in the make-up of renewable generation will see LPR continue to change over the next 10 years.

3.39 The Authority expects LPR will likely change over the next ten years, especially with the transition to 100% renewable generation and other key developments, such as the implementation of Real-Time Pricing (RTP).

3.40 The Authority expects some change to LPR will be driven by greater nodal price volatility, caused by increasing operation of intermittent renewable generation (solar and wind) and nodal scarcity pricing.[25] However, some of this volatility may be mitigated through the physical management of price risk. For instance participants may respond to price changes by changing demand levels or through dispatch notification for smaller market participants as part of RTP. The forthcoming changes to the Transmission Pricing Methodology may incentivise participants to mitigate LPR by contributing to grid upgrades.

3.41 With the transition to 100% renewable generation, there is the possibility that changes in the makeup of renewable generation could result in changes to the pattern of

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24 Figure 10, Electricity Commission, *Consultation Paper: Managing locational price risk proposal, September 2010.* Available here: 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/#c8177.

25 Nodal scarcity pricing, also known as scarcity pricing, introduces a price floor and price cap mechanism during scarcity, providing revenue certainty for providers of last resort resources (generation and demand response), while also giving more assurance to wholesale purchasers that spot prices will not be unreasonably high.

transmission flows and nature of locational and other price risk. For example, with increased wind and solar generation, the dominance of hydro-generation is expected to decrease over time. If this were to occur, then the pattern of electricity flow might change from the currently predominant South to North flows to more variable patterns depending on wind and sunshine. The change in power flows will alter inter-island and inter-regional LPR and will be an important consideration for the Authority on how it aligns with efficiency limb of the statutory objective.

3.42 The Authority also expects potential new sources of LPR to arise as New Zealand diversifies and invests in different sources of renewable generation. For example, the increase in solar investment taking place in the upper North Island might create new sources of risk between Northland and the rest of the transmission network.

The Authority has made several observations regarding the current policy settings of the FTR market

4.1 The objective of introducing FTRs was to promote competition in the electricity industry for the long-term benefit of consumers – in accordance with the first limb of Authority's statutory objective.[26]

4.2 In 2020, concerns were raised by market participants with the Authority regarding the operation of the FTR market.[27] Questions were also raised by the Authority's Board members following the FTR and wholesale market review.

4.3 As part of the Authority's strategic focus on efficient risk markets to support the transition to 100% renewable generation, the Authority is assessing the current FTR market and LCE allocations to understand the issues and opportunities that exist.

4.4 In this section the Authority considers the extent to which the FTR market has:

(a) enhanced retail competition, and

(b) enhanced regional generator competition.

4.5 In particular, the Authority is considering the impact the FTR market has as a mechanism for managing LPR, including:

(a) the cost to support the FTR market,

(b) if policy settings mean some or all FTR participants are not using the market to manage LPR (ie. they may be profiting from FTR market with little or no benefit for consumers, although it is understood some FTR participants are using FTRs as a proxy for energy hedges),[28]

(c) how tightly targeted the FTR market is to managing LPR, and

(d) why parties (particularly direct connect consumers and independent retailers) who are subject to LPR are not using the FTR market.

4.6 The Authority has also made observations about features of the FTR market that appear to either work against, or do not support, the long-term interests of consumers.

[26] Paragraph 1.4.3, Electricity Authority, *Information Paper: Improving the Opportunity to Hedge New Zealand Electricity Prices.* Available here: Microsoft Word - Locational hedge proposal consultation paper_For public release (6).DOC.

[27] Available at https://www.ea.govt.nz/assets/dms-assets/29/Letter-to-the-requestor-26-November-2021.pdf

[28] Given that the loss component of LCE makes up a high portion of total LCE and is highly correlated with energy prices.

Retail competition has improved since the FTR market started, but the FTR market's contribution is not clear

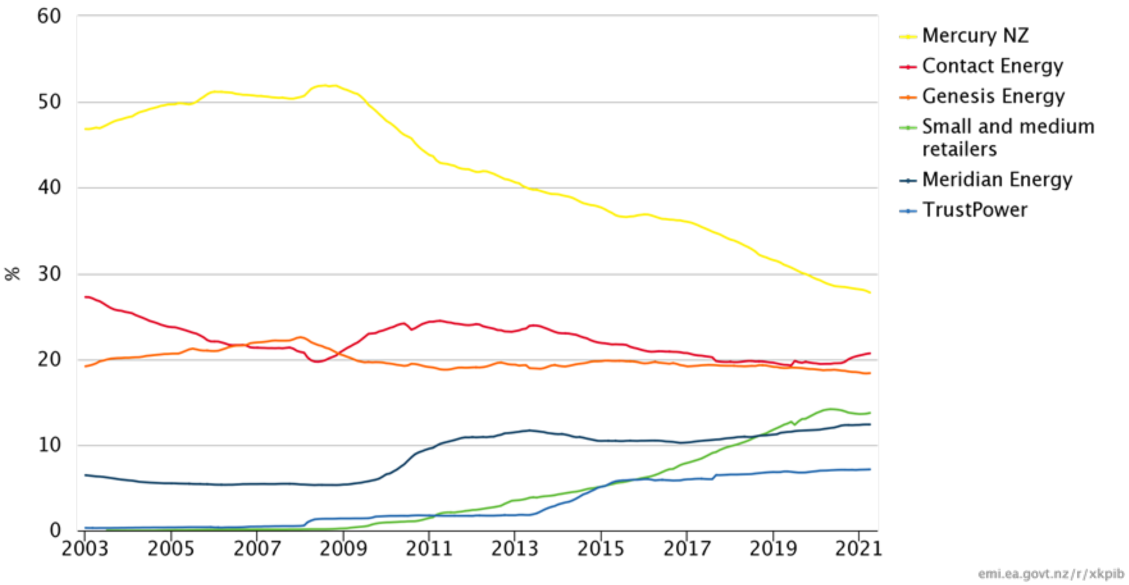
> **Observation 2:** Retail competition has increased over time, however it is difficult to determine the influence that FTRs have on retail competition.

4.7 Since the inception of the FTR market in June 2013 the market share of incumbent retailers has reduced, while the market share of other retailers has increased significantly, resulting in a more competitive retail environment. This is shown in the following five charts, Figures 4 - 8.

These charts show the trends in retail market shares for the five largest generator retailers (Contact, Genesis, Mercury, Meridian, and Trustpower) and the remaining retailers (combined) for the Upper North Island (UNI), Central North Island (CNI), Lower North Island (LNI), Upper South Island (USI), Lower South Island (USI) regions over the past 18 years.[29]

4.8 In all five regions there has been an increase in the market share of small and medium retailers since the inception of the FTR market in June 2013. This has largely come at the expense of market share by the incumbent retailers.[30] However, in all five regions there had already been substantial reductions in incumbent retail market share before FTRs were introduced.

Figure 4 Upper North Island retail market share trends



29 Note that the horizontal axis markers indicate the end of the stated year (not the beginning).

30 Although this isn't always the case. In the USI region, the current market share of one of the incumbents (Meridian) is similar to what it was in June 2013, while there has been a decline in the market share of the other four large generator-retailers.

Figure 5 Central North Island retail market share trends

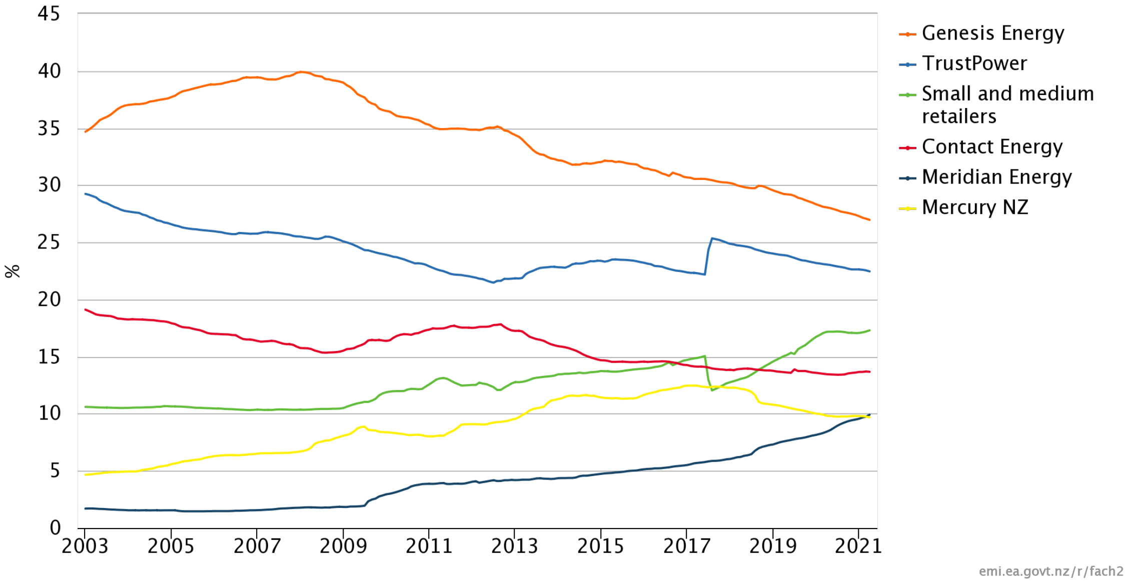


Figure 6 Lower North Island retail market share trends

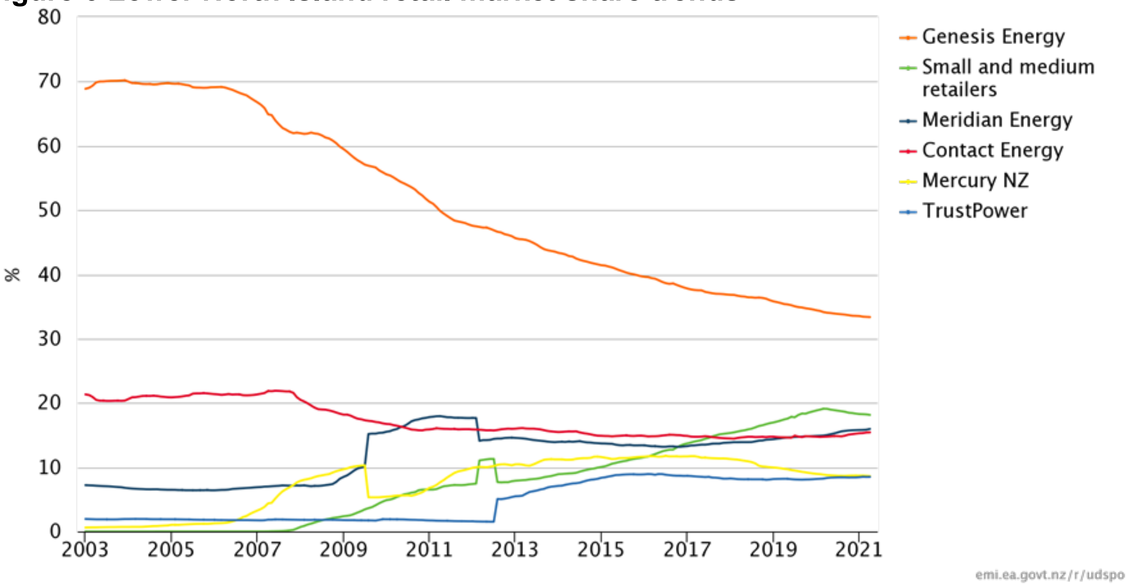


Figure 7 Upper South Island retail market share trends

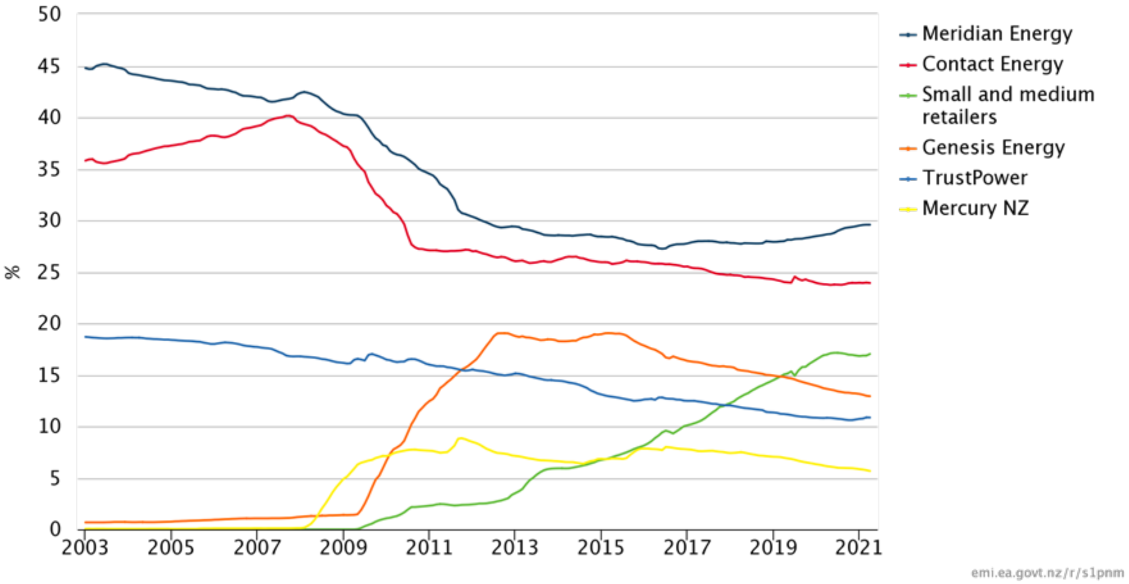
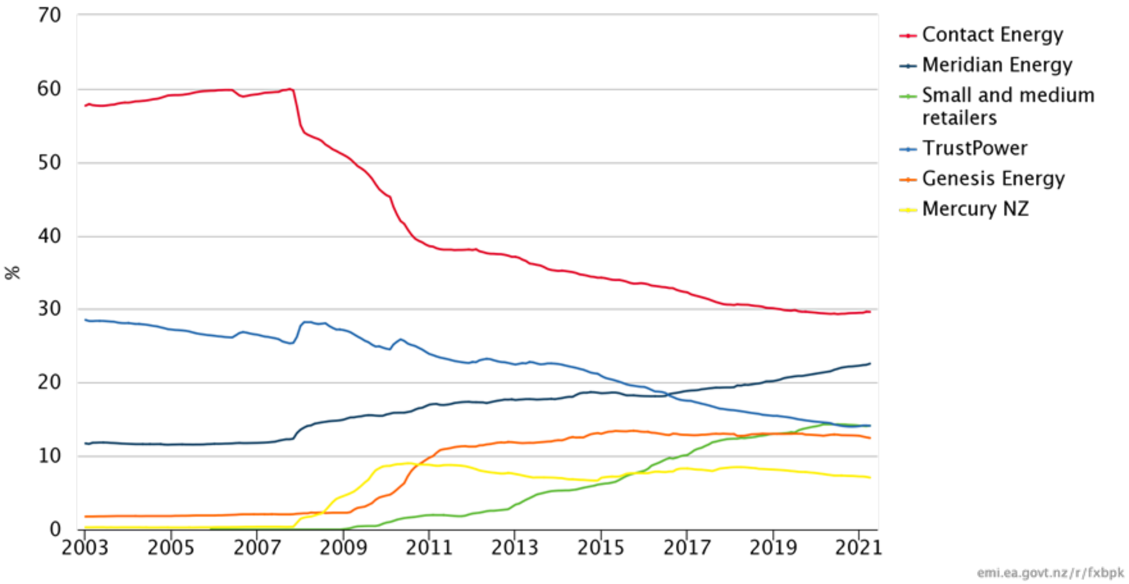


Figure 8 Lower South Island retail market share trends



4.9 However, there have been a range of other changes that occurred during (and just prior) to the period since June 2013 that have likely contributed to enhanced retail competition. These changes include:

(a) virtual assets swaps between some of the generator retailers,

(b) the ownership transfer of the Tekapo A and B power stations from Meridian to Genesis,

(c) changes to the Australian Securities Exchange (ASX) NZ electricity futures and options market (including voluntary market-making arrangements and a reduction in contract size from 1 MW to 0.1 MW, increased volumes of market made contracts and lower bid/offer spreads),

(d) lowered barriers to enable lines companies to retail subject to certain conditions, and

(e) improvements in the standardisation of distributors' use-of-system agreements and tariff structures.

4.10 Therefore, it is difficult to determine any incremental retail competition benefits due specifically to the FTR market. However, two respondents to the Authority's survey in its post-implementation review of FTRs said that FTRs had been a significant factor in enabling them to expand their retailing into new geographical areas.[31]

The effect on retail competition in Hawkes Bay from introducing the Redclyffe hub is unclear

4.11 The Authority considered a localised example of retail competition to determine if there is a link between an increase in retail competition and the introduction of FTRs. One of the new FTR hubs introduced in May 2018 was Redclyffe in the Hawkes Bay.[32] If the FTR market is enhancing retail competition by making it easier for retailers to manage LPR then the introduction of the Redclyffe FTR hub would have improved retail competition in the Hawkes Bay. The introduction of the Redclyffe FTR hub may also have made it easier for retailers to manage some LPR in Gisborne, however as constraints do occur between the Hawkes Bay and Gisborne[33], any improvement in retail competition would be less in Gisborne than it is in the Hawkes Bay.

4.12 Retail competition data in both the Hawkes Bay and Gisborne suggests there is no obvious improvement in retail competition in the Hawkes Bay relative to Gisborne since the Redclyffe FTR hub was added. This conclusion is based on the following observations (which are shown in Figures 9 - 11 below):

(a) the market share of incumbents in Hawkes Bay and Gisborne both fell post-2018, but this was a continuation of downward trends that started much earlier,

(b) the market share of small and medium retailers in Hawkes Bay and Gisborne grew following the introduction of the Redclyffe FTR hub, but this growth commenced well before the Redclyffe FTR hub was introduced, and

(c) the unregulated components of electricity bills (retail and energy components) for Napier (used as a proxy for Hawkes Bay) and Gisborne have all grown since 2018 and Napier's energy component has grown faster than Gisborne's energy component. Some of this increase appears to be due to underlying energy costs in New Zealand.

4.13 Therefore, it is not clear that the introduction of the Redclyffe FTR hub has had any impact on retail competition in the area.

31 Research report can be found at https://www.ea.govt.nz/assets/dms-assets/26/26804Perceptions-of-Financial-Transmission-Rights-Research-Report.pdf.

32 In May 2018 RDF2201 was introduced as an FTR hub. Retail purchases are made downstream from RDF2201 at the RDF0331 grid exit point. While constraints can occur between RDF2201 and RDF0331, prices are generally highly correlated between the two points (correlation coefficient of 0.97).

33 The spring washer effect occurs on occasions between Redclyffe, Fernhill and Tuia creating high prices at Fernhill and Tuia.

Figure 9 Hawkes Bay retail market share trends

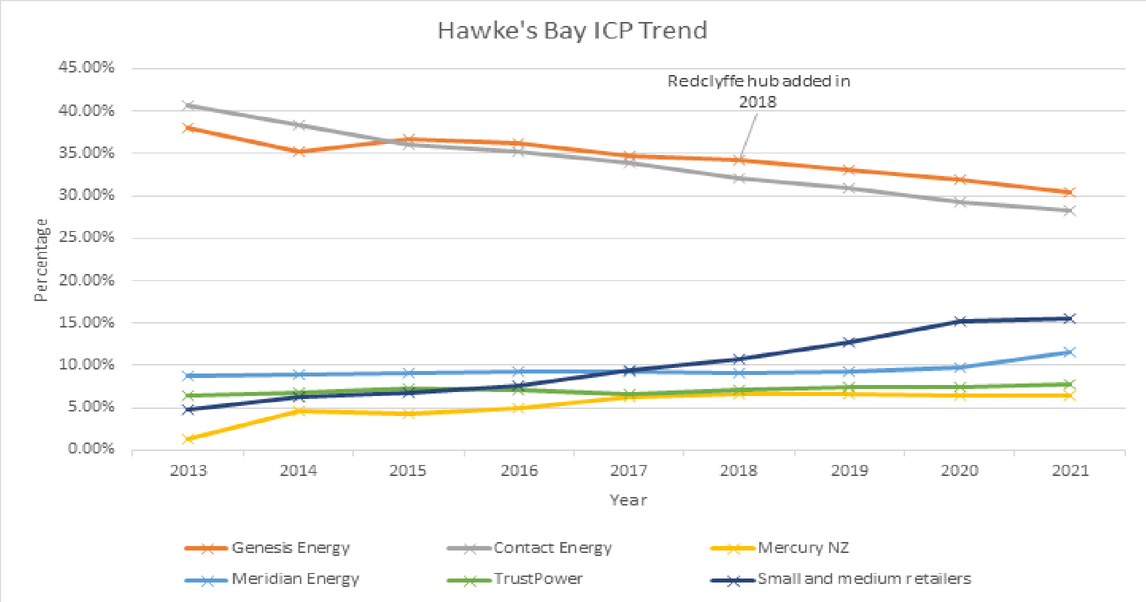


Figure 10 Gisborne retail market share trends

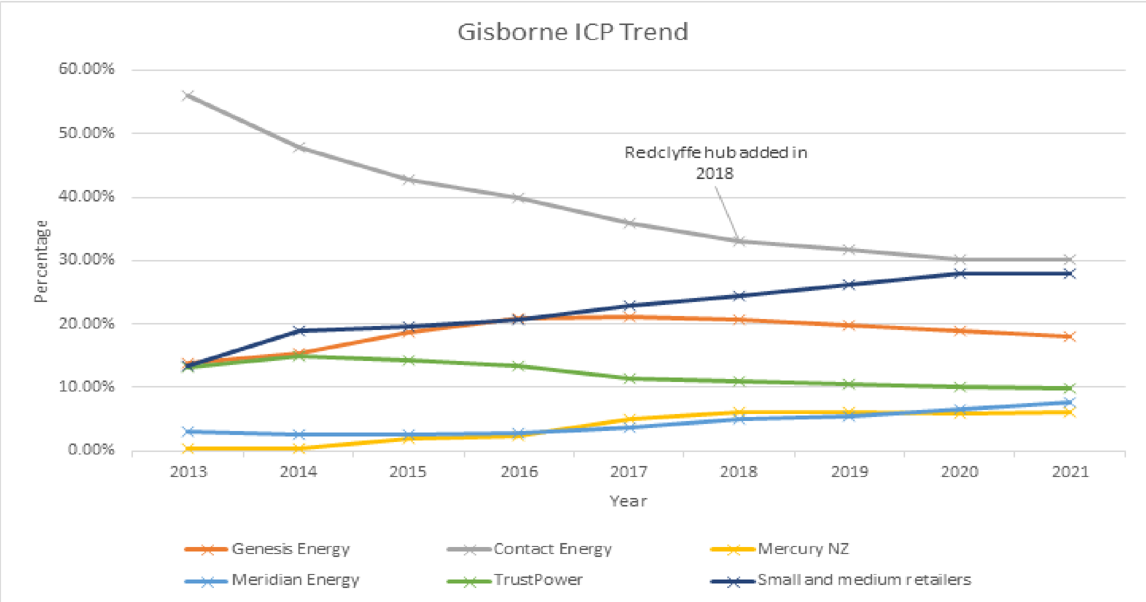
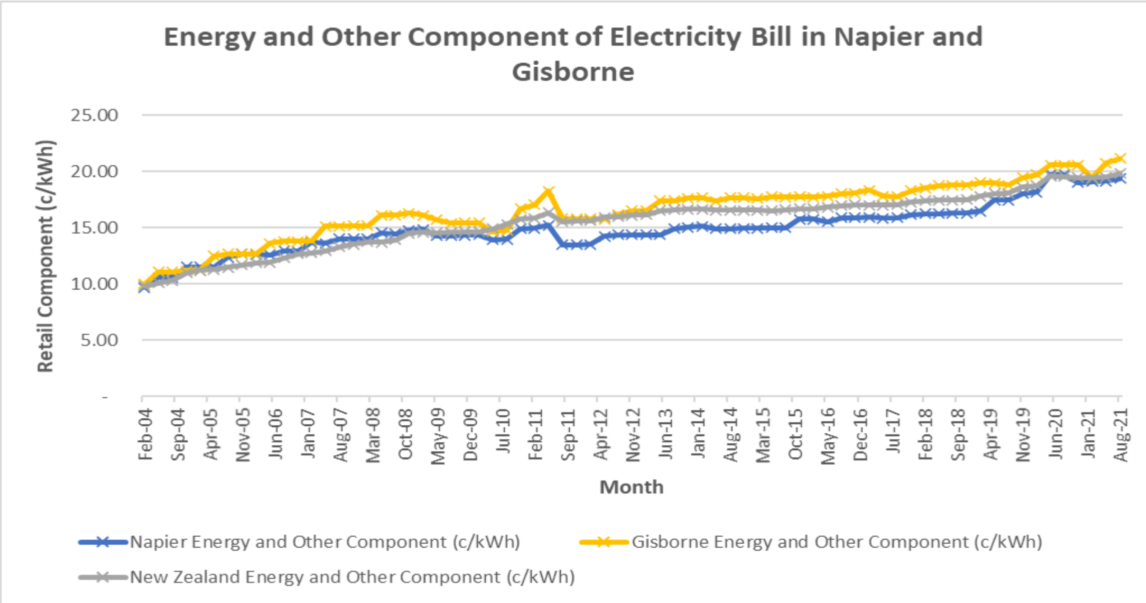


Figure 2 Retail and energy components of Napier and Gisborne electricity bills



There has been no discernible effect on regional generator competition due to FTRs

Observation 3: There has been no apparent impact on generator competition due to FTRs.

4.14 One of the expected benefits from the introduction of FTRs was increased generator competition due to generators locating in regions subject to LPR. This relates directly to the competition and efficiency limbs of the Authority's statutory objective.

4.15 However, it is not clear that any decisions on where to locate generation investment have been affected by the introduction of FTRs. Significant power stations commissioned since 2013 are listed in Table 3, below.

Table 3 Significant power stations[34] commissioned since the start of the FTR market

Power scheme	Owner	Technology	Location	Commission Date
Amethyst	Westpower	Hydro	West Coast	2013
Esk	Trustpower	Hydro	Hawkes Bay	2013
McKee	Todd Energy	Thermal	Taranaki	2013
Ngatamariki	Mighty River Power	Geothermal	Waikato	2013
Rochfort	Kawatiri Energy	Hydro	West Coast	2013
Mill Creek	Meridian Energy	Wind	Wellington	2014
Te Mihi	Contact Energy	Geothermal	Waikato	2014
Flat Hill	Pioneer Generation	Wind	Otago / Southland	2015
Te Ahi O Maui	Eastland Generation	Geothermal	Bay of Plenty	2018
Ngawha - Expansion	Top Energy	Geothermal	Northland	2020
Matiri	Southern Generation Partnership	Hydro	Nelson / Marlborough	2020
Junction Road	Nova Energy	Gas	Taranaki	2020
Waipipi	Mercury Energy	Wind	Taranaki	2021
Turitea[35]	Mercury Energy	Wind	Manawatu	2021

4.16 For many of the power stations commissioned in 2013-2015 the decision to proceed with the investments would have been made before the FTR market was established.

34 Power stations with capacity greater than 4 MW.

35 Turitea (which includes Turitea North and Turitea South) is only partially commissioned.

4.17 However, even for the power stations commissioned later, the primary factors driving the location of many of the new generation stations seem to be proximity to fuel and ease of connection to the grid. Proximity to load is also likely to be a consideration in some cases.

4.18 For example, Trustpower (the original developer of the Waipipi wind farm) noted that the Waipipi site was attractive because it was more exposed to a southerly wind flow than the company's Tararua wind farm, the site was flat and not overly complex, the wind farm could help it more effectively store water in its nearby Patea hydro scheme, and it was ideally located to provide generation to Auckland and Wellington's large urban loads.[36]

4.19 There has not been public indication that any of the power stations listed in Table 3 or any recent commitments to develop power stations (such as Meridian's Harapaki wind farm in the Hawkes Bay and Contact's Tauhara geothermal plant in the Waikato) were swayed by the existence of the FTR market. In addition, no respondents to the Authority's survey for its post-implementation review of the FTR market said FTRs had helped them locate generation in new areas.[37]

The costs to support the FTR market are high

Observation 4: FTRs currently use an average of $5.29 million per month from LCE (~47% of total LCE) to settle.

4.20 FTRs are funded using a combination of FTR auction revenue and FTR rentals from the LCE allocation. Any of the LCE allocation not needed to fund FTR payments is given to Transpower to allocate to transmission customers.

4.21 It was proposed that the revenue to support revenue adequacy would come from any premium above the value of the FTR rental. This was assuming a risk-averse buyer would pay a premium above the full value of the FTR rental, which would result in total auction revenue exceeding the quantity of rentals for FTR settlement.[38]

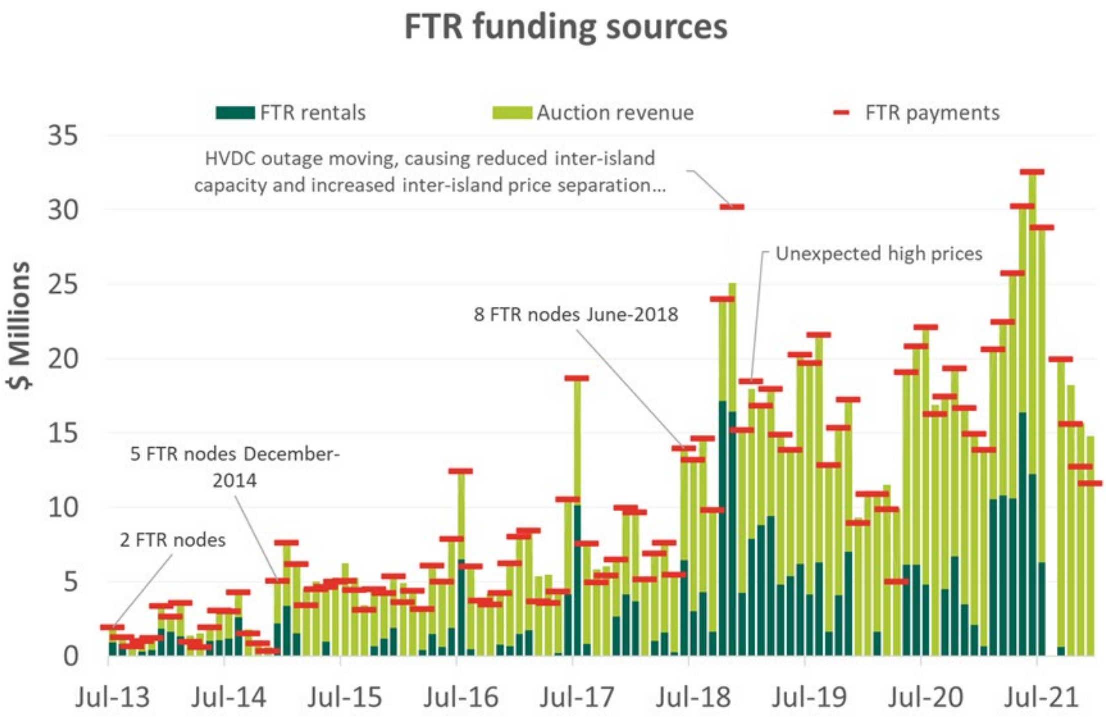
4.22 However, that Authority have observed aggregate FTR funding to have increased over time since the FTR market started in 2013. This suggests a misalignment with the efficiency limb of the Authority's statutory objective. This is largely due to increases in the number of FTR hubs in 2014 (from two hubs to five hubs) and in 2018 (to eight hubs). Auction revenue has increased (due to auctioning additional FTRs) and there has also been an increase in the LCE allocation for FTR rentals due to contributions from additional network sections. This is shown in Figure 12 below.

36 Energy News, available here: https://www.energynews.co.nz/news-story/9144/trustpower-seek-consents-50-turbine-waverley-wind-farm and https://www.energynews.co.nz/news-story/wind/28984/waverley-ideally-placed-meet-north-island-demand.

37 Electricity Authority, *Perceptions of Financial Transmission Rights.* Available here: https://www.ea.govt.nz/assets/dms-assets/26/26804Perceptions-of-Financial-Transmission-Rights-Research-Report.pdf

38 Paragraph 3.4.141, Electricity Authority, *Consultation paper: managing locational price risk: Proposed amendments to Code.* Available here: Consultation Paper (ea.govt.nz)

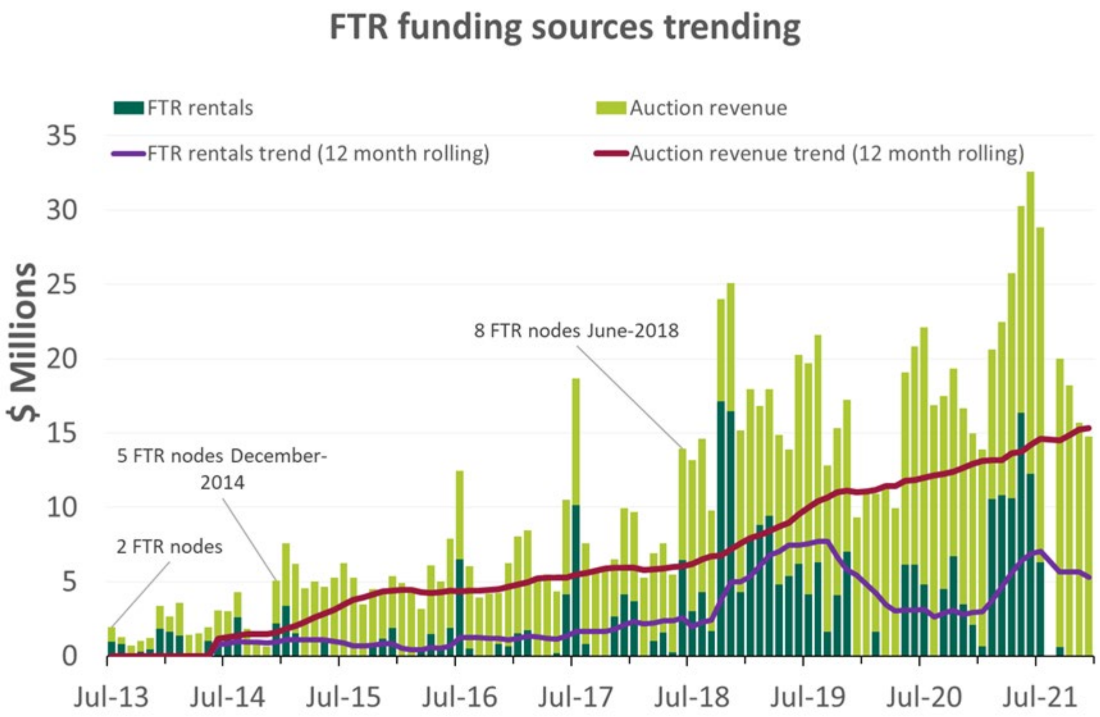
Figure 32 FTR funding sources (July 2013 – December 2021)



4.23 The average amount of LCE required to support the FTR market has also been increasing as the FTR market has expanded. The long-term average LCE required to support the FTR market has increased from $0.77 million per month (13% of total LCE) where there were two FTR hubs to $1.34 million per month (17% of total LCE) with five FTR hubs and currently sits at $5.29 million per month (47% of total LCE) with eight FTR hubs.

4.24 Figure 13 illustrates the LCE required to support the FTR market and how this has increased as the FTR market has grown. Auction revenue has been increasing over the last couple of years while FTR rentals show no net increase. Auction revenue is expected to be less volatile than LCE and FTR settlement, as auction revenues are based on expectation. Also, since auction revenues are set up to 24 months ahead they will tend to show a lagged trend, if energy prices (and FTR payouts) are trending upwards.

Figure 43 FTR funding sources trending (July 2013 – December 2021)



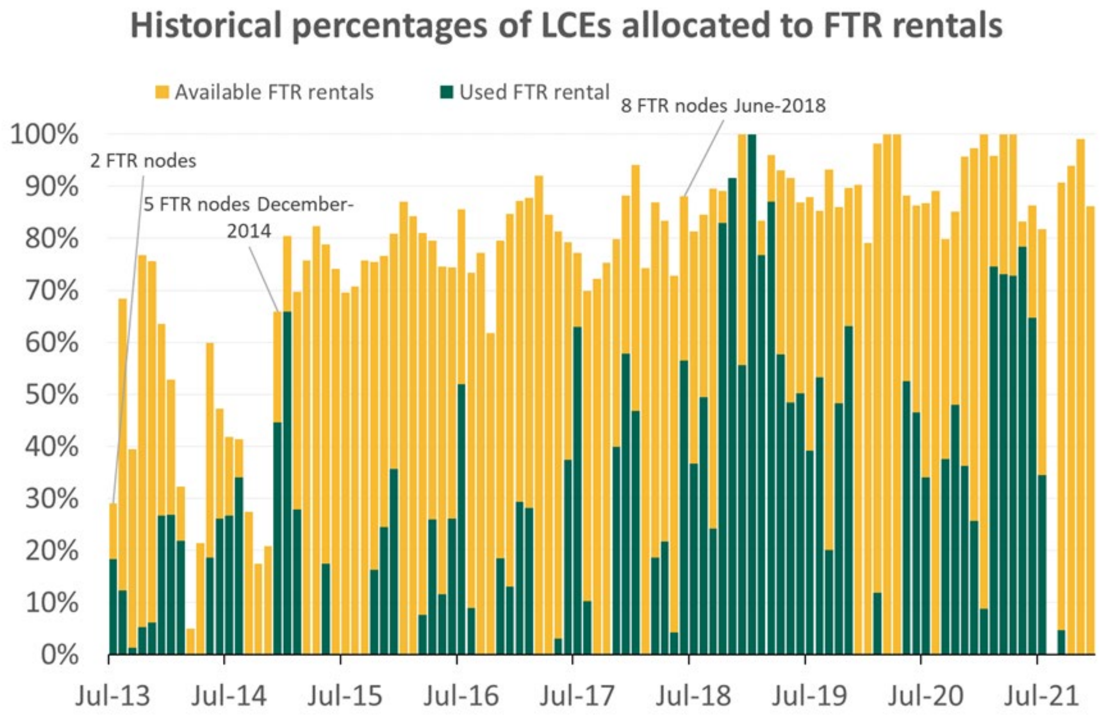
Increase in FTR hubs sees a higher proportion of LCE made available for the FTR market

4.25 This is also reflected in the proportion of LCE allocated to FTR rentals (shown by the yellow bars in Figure 14) – much of this increase will be due to the increase in the number of FTR hubs (particularly the increase from two FTR hubs to five FTR hubs in December 2014) increasing the amount of LCE available for the settlement of FTRs.

4.26 Since June 2018 onwards (when the FTR market was increased to eight FTR hubs) an average of 90% of total LCE was made available to settle FTRs, while prior to this date an average of 70% of total LCE was available to settle FTRs.

4.27 However, the proportion of LCE required to fund the FTR market has increased since 2018 as spot prices have increased (shown by the green bars in Figure 14).

Figure 54 Proportion of LCE allocated to FTR rentals

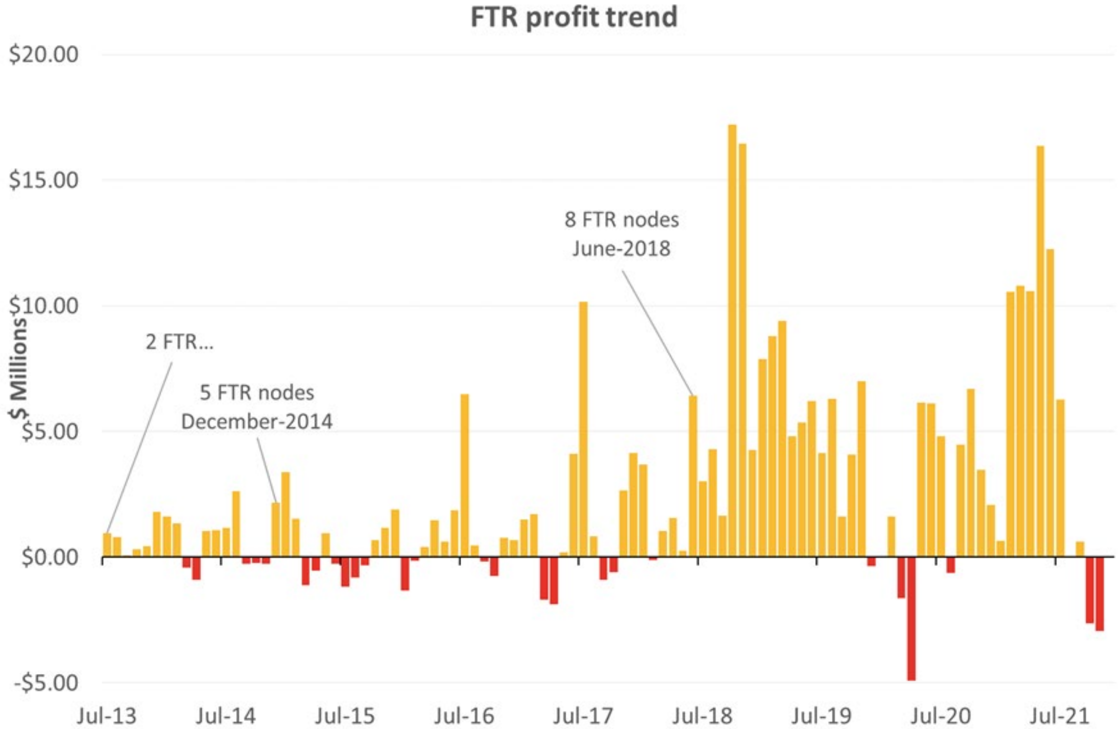


Some FTR participants profits may not be directly related to consumer benefit

Observation 5: Some parties may be consistently profiting from FTRs without a clear benefit to consumers.

4.28 FTR participants have profited from the FTR market since its inception—the number of months where LCE has been required to support the settlement of FTRs has significantly outnumbered months where there was more auction income than payments. In addition, FTR profits have increased over time—this may be due to the increase in the number of FTR hubs and increase in FTR capacity made available by the FTR manager. This is shown in Figure 15 below.

Figure 65 Monthly FTR profit (July 2013 – December 2021)



4.29 Figure 16 below, shows the acquisition cost of FTRs has steadily increased over time, while the settlement amount (the amount paid out to FTR purchasers) has also increased.[39] At least some of these increases are likely due to the introduction of additional FTR hubs. While there has been some step up in average FTR profit[40] in the past four years, the growth has been less pronounced than the increase in the acquisition cost and settlement amount. When FTR profits are viewed on an annual basis, aggregate profits have peaked at approximately $65 million per annum in the past four years.

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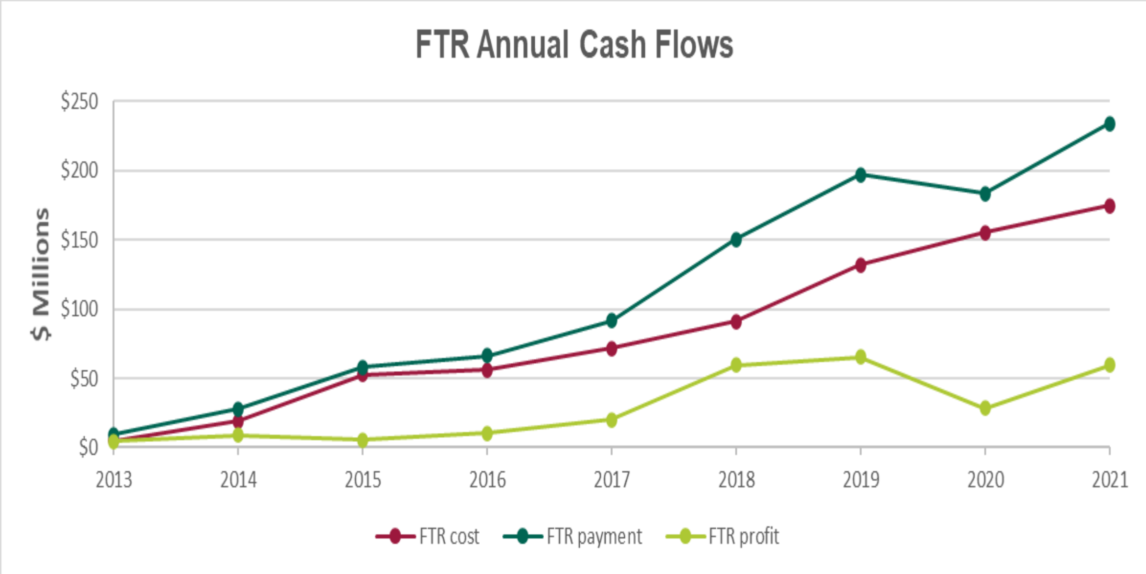
39 Note that the settlement amount paid out has been more volatile than the acquisition cost. This is expected—FTRs are paying out on location price differences, which are volatile, and why a mechanism for managing LPR (such as FTRs) is needed.

40 Note that FTR profit is equal to the settlement amount less the acquisition cost.

Figure 76 Annual FTR cashflow (CY2013 – CY2021)

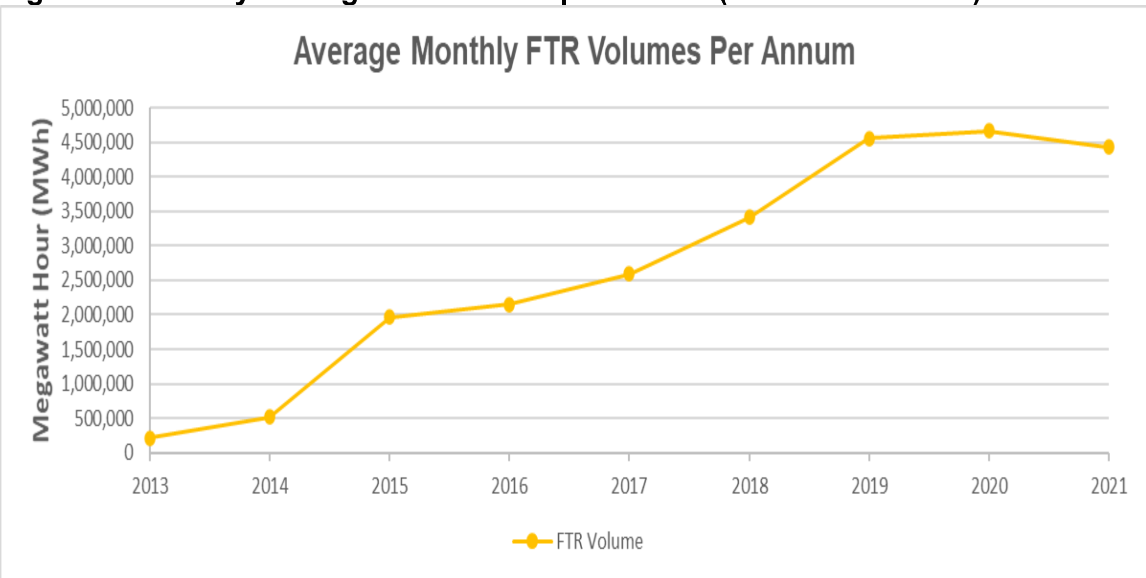


4.30 Table 4 shows the observed performance for all FTR participants between the years 2013 and 2021.

4.31 When all FTR participants are observed collectively, months are profitable 2/3 of the time (66%) with the average profit per MWh for each FTR participant being $0.78/MWh.

4.32 To provide some context against FTR volume traded, below in Figure 17 is the average monthly FTR volume in MWh for the years between 2013 and 2021.

Figure 87 Monthly Average FTR volume per annum (CY2013 – CY2021)



4.33 Note that data presented does not include August 2021 because the transactions for the month are yet to be settled due to the ongoing 09 August peak demand event investigation.[41]

41 Reference: https://www.ea.govt.nz/assets/dms-assets/29/9-August-2021-UTS-Preliminary-decision-paper.pdf

Table 4 Monthly FTR profit and loss by FTR participant (2013 – 2021)[42]

Participant Number	% of profitable months	Profit/loss per MWh
1	100.00%	$5.57
2	92.86%	$3.45
3	68.63%	$0.85
4	82.95%	$0.57
5	74.26%	$0.96
6	59.09%	$1.20
7	82.05%	$1.32
8	100.00%	$5.84
9	32.43%	-$2.03
10	52.13%	$0.76
11	78.22%	$1.22
12	54.17%	$0.11
13	62.75%	$0.20
14	22.22%	-$6.67
15	69.61%	$1.19
16	25.00%	-$0.04
17	N/A	N/A[43]
18	43.24%	-$0.20
19	60.00%	$0.16
	Overall % of profitable months for all months **66%**	**Weighted average of profit/loss per MWh for all months** **$0.78**

4.34 The profitability of FTRs may suggest they are inherently undervalued. FTR participants are benefiting from this undervaluation and it is not immediately clear how the Authority maintaining and operating the market, and allowing the use of LCE to support the settlement of these FTRs, contributes to the long-term benefit of consumers.

4.35 Some FTR participants have purchased FTRs at a loss, in this situation FTRs could form part of a wider hedging strategy that on average does not require a large amount of LCE.

42 Excluding profit/loss on disposal prior to settlement, ie, only includes FTRs held to settlement

43 FTRs were sold via reconfiguration auction prior to settlement

4.36 Some of the participants that purchase FTRs do not have exposure to LPR, and their use is not directly linked to management of locational price risk from the spot market. It is important to note that the presence of non-physical financial parties increases the settlement price of FTRs and contributes to the efficiency of the FTR price. An efficient FTR price should not require both LCE and auction revenue to settle the market over the long term. Fewer FTR participants would likely result in a greater share of LCE being used for the settlement of the FTR market.

Observation 6: The LPR due to losses is highly correlated with energy prices while LPR due to constraints is not.

The FTR market is not tightly targeted at the LPR problem

4.37 The FTR market pays out on locational price differences due to both constraints and losses. Loss rentals are highly correlated with energy prices (around 90% for the period 2013-2021) so do not contribute significantly to LPR. However, the correlation between constraint rentals and energy prices was about 1% for the period 2013 - 2021 and is a large source of LPR.

4.38 However, as indicated in Table 5 below, the majority of FTR rentals, and consequently profits from the FTR market, are related to loss rentals.[44]

Table 5 FTR rental decomposition (2013 – 2021)

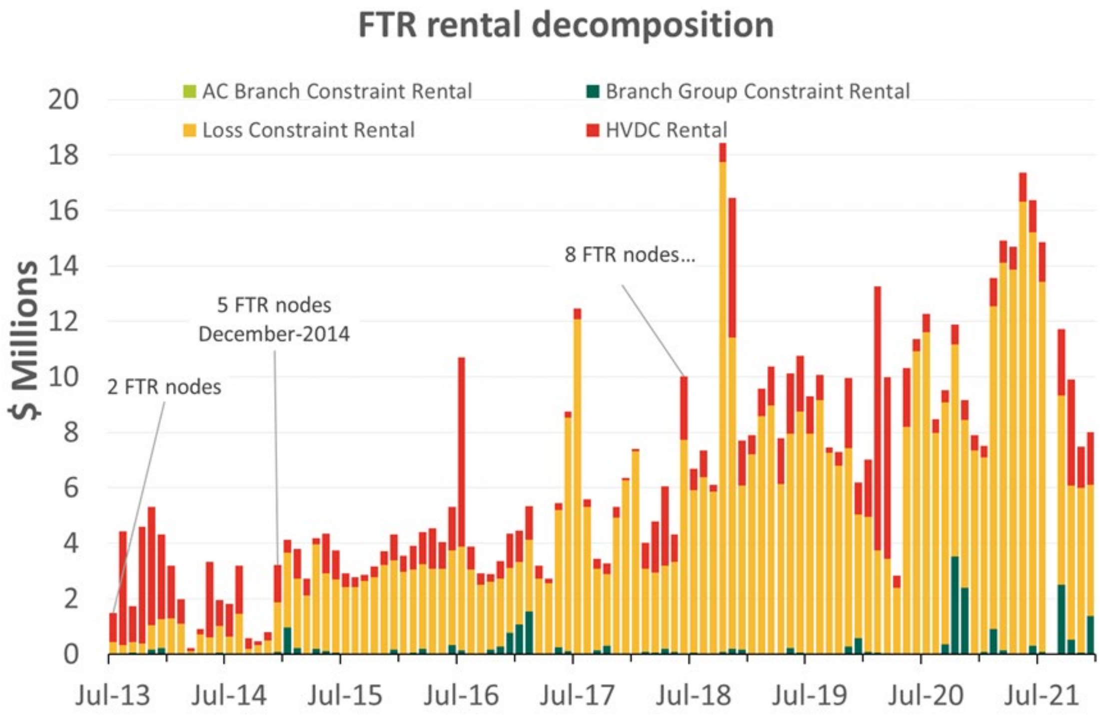
FTR rental component	% of total FTR rental (2013 – 2021)
AC branch constraint rental	0.01%
Branch group constraint rental	2.85%
Loss constraint rental	77.17%
HVDC rental	19.97%

4.39 The breakdown of FTR rental components is provided in Figure 18. The majority of the FTR rental is contributed from loss constraint rentals and HVDC rentals, with a small contribution from branch group constraint rentals and negligible contribution from AC branch constraint rentals.[45]

44 Loss constraint rental in Table 4 refers to the amount of LCE generated by each AC line loss curve block that is to be applied to settlement of FTRs (as defined in Schedule 14.3 of the Code). This is commonly referred to as “loss rentals”.

45 “AC branch constraint rental” in, Table 4 and Figure 17 refers to the amount of LCE generated by individual branch limits. Typically branch group constraint limits are reached before individual branch limits.

Figure 98 FTR rental decomposition (July 2013 – December 2021)



4.40 For example, the FTR product, [BEN_ISL] relates to a path between Benmore and Islington that has extremely high correlation between the nodal prices at Benmore and Islington, as well as infrequent periods of price separation.[46] Refer to Figure 19.

Figure 109 Correlation between prices at Benmore and Islington (July 2013 to December 2021)

[46] Between June 2013 and December 2021 price separation for BEN_ISL was over 20% (and above the average price separation of $6.06) 0.05% of the time (less than 100 trading periods). Although 50,000 trading periods exceed $6.00 and 100 trading periods exceed $64.

Many parties who are subject to LPR are not using the FTR market.

Observation 7: Many parties (particularly direct connect consumers and independent retailers) who are subject to LPR are not using the FTR market.

4.41 Many parties (particularly direct connect consumers, independent generators and independent retailers) who are subject to LPR are not directly using the FTR market.

4.42 A table of direct connect consumers and retailers who may be subject to LPR are listed in Table 6 below. A list of non-physical financial entities who have participated in the FTR market has been provided for comparison.

4.43 Only retailers with over 75 ICPs have been included as this is approximately equivalent to the minimum FTR contract size of 0.1MW, although there are no restrictions on retailers with less than 75 ICPs or consumer demand less than 0.1MW from also participating in the FTR market.

Table 6 Direct consumers and retailers who may be subject to LPR

Direct consumers	Retailers	Non-physical financial entities
New Zealand Aluminium Smelters New Zealand Steel OJI Fibre Solutions Pan Pac Forest Products The New Zealand Refining Company Winstone Pulp International	**Genesis Energy** **Contact Energy** **Meridian Energy** **Mercury NZ** **Trustpower** Nova Energy Pulse Energy Alliance Electric Kiwi Vocus **Flick Electric** Ecotricity Ourpower **Pioneer Energy** Prime Energy For Our Good Paua to the People Hanergy	Deutsche Bank OM Financial Ltd Smartwin Energy Trading Ltd Macquarie Equipment Finance Ltd MMA Energy Haast Energy Trading Ltd The Three Tasters Nodal Traders Ltd Mercuria New Zealand Ltd Prime Energy Ltd Acropolis Energy Trading Ltd

4.44 Direct consumers and retailers in **bold** are already registered FTR participants currently participating in the FTR market.

4.45 One of the non-physical financial entities, Deutsche Bank has not participated in the FTR market since late 2013.

4.46 Some retailers are known to have access to hedging products including FTRs via an affiliated company. For example, Electric Kiwi shares common ownership with Haast Energy Trading Limited, who is an electricity trading company.

4.47 Due to client confidentiality, brokerage firms are unable to disclose if direct connect customers or retailers are participating in the FTR market via their services, This is an important consideration, and one which links to the Authority's statutory objective of long-term consumer benefit, as it means the Authority cannot be certain whether some parties are participating or not.

4.48 It is important for the Authority to understand the potential barriers preventing direct customers and retailers from participating in the FTR market, along with solutions to improve participation.

A UMR survey conducted in 2017 identified complexity and cost as barriers to participating in the FTR market

4.49 In 2017, on behalf of the Authority, UMR surveyed electricity industry participants about their perceptions of FTRs.[47] Twenty respondents were surveyed via telephone interviews including seven independent retailers, seven generator-retailers, three financial entities and five large direct consumers.

4.50 Two key themes emerged from the survey when respondents were asked for suggestions of improvements and barriers to competition.

In 2017 the complexity of the FTR market was considered a barrier to participation

4.51 Complexity was one of the themes that emerged from the 2017 UMR survey. There were mixed views on the perceived complexity of the FTR market, which was associated with the number of FTR hubs[48]. Some respondents felt it would be beneficial to reduce the complexity of the market.

4.52 Survey respondents noted complexity was perceived to be a detriment to entry by new participants and for electricity end users and may disproportionally benefit well informed financial entities without a physical presence in the New Zealand electricity market.

4.53 Some respondents considered that a level of complexity was required for the FTR market to serve its purpose. There was a view that FTR participants need to commit to investing time and resource to participate in the FTR market, and the FTR market should not be designed to meet the needs of only a subset of FTR participants.

4.54 Many respondents considered clearer information and education for prospective FTR participants could help overcome this barrier.

4.55 Education initiatives were identified as needing to cater for current or potential FTR participants of various levels of understanding from the basics to more technical information.

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47 Research report can be found at https://www.ea.govt.nz/assets/dms-assets/26/26804Perceptions-of-Financial-Transmission-Rights-Research-Report.pdf.

48 A reason for the perception of increased complexity is because the number of FTR paths available to purchase increases exponentially as more FTR hubs are added.

In 2017 the costs to participate were considered a barrier to participation

4.56 The 2017 UMR survey identified the amount of internal resource needed was a barrier to participating in the market.

4.57 There was a perception that the majority of the volumes within the FTR market were acquired by skilled participants who have the capacity and resources to participate and that organisations need a similar level of skill and sophistication to compete.

The Authority identified other aspects of the FTR market that raise potential concerns

4.58 The Authority made some observations about features of the FTR market that appear to either work against, or do not support, the long-term interests of consumers.

The FTR market has generally returned a profit to FTR holders

> **Observation 8:** FTRs tend to trade somewhat below 'fair value.'

4.59 The Authority has observed that FTRs are persistently profitable, meaning the FTR settlement often exceeds FTR acquisition costs. This suggests the market may not be reaching equilibrium, with no clear reason why.

4.60 This can be characterised as FTRs trading below 'fair value[49]'. The Authority speculates a potential reason may be barriers to entry into the FTR market, as greater demand for FTRs would imply prices closer to 'fair value'. However, further work is required to understand the underlying issue of the difference between FTR fair value and FTR purchase prices. This difference may lie through inefficiency in the FTR market. The inefficiency may arise from market failures such as barriers to entry to the FTR market or asymmetric information between participants about the FTR market.

4.61 As a result, this means the FTR market has transferred wealth from transmission customers (who otherwise would have received the residual LCE) to the FTR holder. This in turn raises the question of whether FTRs should trade at/or closer to 'fair value'.

4.62 Below, figure 20 shows the average monthly FTR profitability (together with the quadratic regression curve) and the monthly generation weighted average price (GWAP). As with any insurance-type product, it shows a mix of occasional high pay-outs (corresponding to periods of high spot price such as winter 2017) and periods where pay-outs are less than the acquisition cost. The Authority further observed these acquisition prices to adjust over time to reflect changing expectations about future pay-outs.

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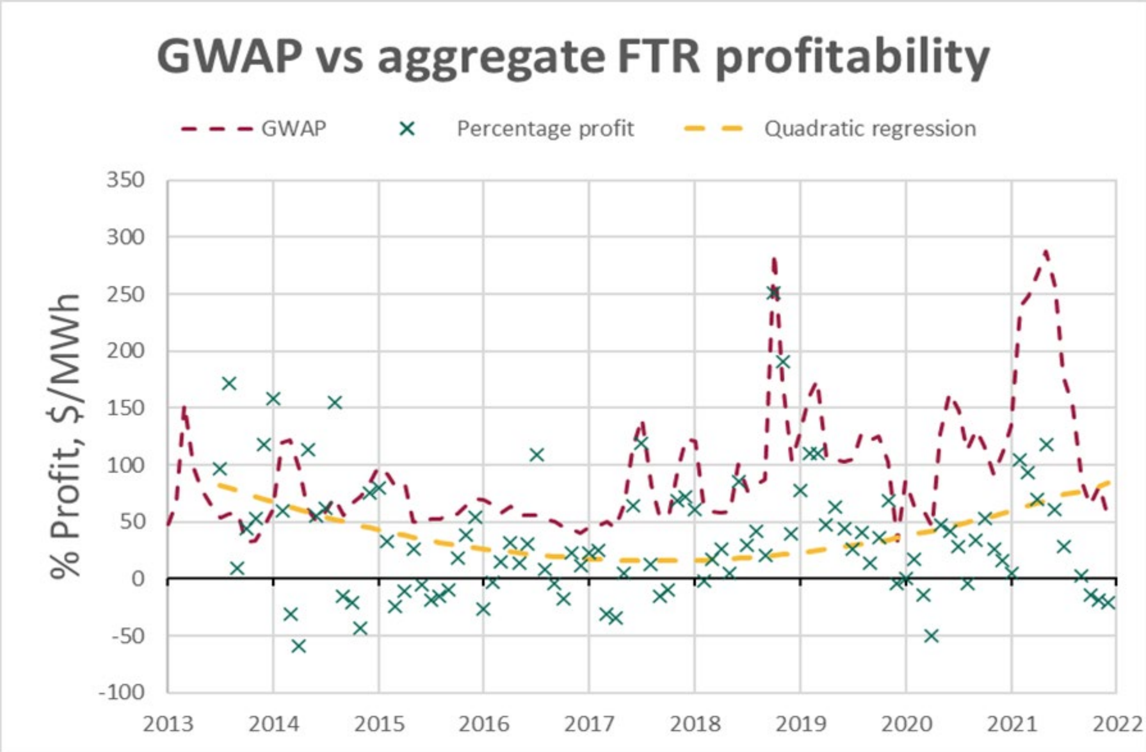
49 A fairly valued FTR would mean over the longer term, the price paid for the FTR at auction is equal to the settlement value of the FTR.

Figure 20: GWAP vs aggregate FTR profitability (July 2013 to December 2021)



~~4.63~~ The Authority also expects improvements to FTR price discovery are aided by speculators participating in the FTR market.

4.64 Whereas the profit from FTR markets accrued to parties involved in generation, retail or hedge markets will remain within the electricity market and can be assumed to flow to consumers due to competitive pressures.

Some features of the FTR market may be unintended

Observation 9: Some features of the FTR market appear to be unintended and have no direct link to consumer benefit

4.65 The Authority has observed some features of the FTR market appear to be unintended and have no clear link to the Authority's statutory objectives of ensuring long-term consumer benefit and increasing the efficiency of the electricity industry. One such example is 'reverse direction' option FTRs.

4.66 'Reverse direction' options are types of FTR that are on path where the physical flow of electricity is always in the opposite direction. For example, ISL_BEN (Islington to Benmore) is a reverse direction option FTR because the usual physical flow of electricity is always from Benmore to Islington.

4.67 Reverse direction option FTR typically settles with a price of zero. The demand for these FTRs is low and can be purchased at the auction for a low price of one or two cents per MWh.

4.68 However, because of interactions with other paths on the transmission system, reverse direction FTRs can be sold back into subsequent auctions for a higher price. For example, suppose someone wants to buy an FTR from ISL_HAY (Islington to Hayward), this implies flow from ISL to BEN and then onto HAY. Once available capacity on ISL_BEN is used up, additional capacity can effectively be purchased from holders ISL_BEN options. Thus, the price that sellers of ISL_BEN options can achieve is a function of the price purchasers of ISL_HAY FTRs are willing to pay. This results in the following:

- traders may be able to make significant returns on a relatively small outlay
- competitive tension between buyers and sellers as holders of 'reverse direction' option FTRs are incentivised to offload them prior to settlement as they will invariably settle at zero
- purchasers of ISL_HAY option end up paying more for something that is worth less – thus traders of 'reverse direction' options are exploiting the fact that FTRs tend to trade below fair value.

4.69 While this tends to increase the price of certain FTR paths towards fair value, it does not boost auction revenue or LCE, which is allocated to transmission customers. Nor does it improve revenue adequacy of the FTR market. The primary activity is a transfer of value to holders of the reverse direction option. This suggests the FTR market may be operating in ways where there is not an immediately clear link to consumer benefit.

Regulatory oversight of the FTR market is limited

> **Observation 10:** The Financial Markets Authority does not regulate trading conduct in the FTR market

4.70 When the FTR market was implemented, it was deliberately designed to reduce the regulatory burden on market participants. However, following its recent review of the trading conduct rules, the Authority is considering whether there should be more rules around trading behaviour in the FTR market.

4.71 Currently, misconduct issues are broadly covered by the Commerce Act, the wholesale market information disclosure obligations in the Code and the Financial Markets Conduct Act regime. However, even with this, regulatory oversight of the FTR market could be improved.

Interactions between auction revenue and revenue adequacy

> **Observation 11:** Revenue adequacy settings of the FTR market contribute to the profitability of FTRs

4.72 FTR settlement is made up of allocated LCE and auction revenue from the sale of FTRs. The decision to fund FTRs using a combination of allocated LCE and auction revenue was made by the Authority in 2011.

4.73 This was justified on the basis it would increase revenue adequacy,[50] which in turn would help ensure FTRs are a reliable tool for managing LPR.[51] At the time of the decision, the Authority also considered it would minimise the transaction costs for participation in the FTR market and support the promotion of competition, through providing participants with the opportunity to utilise revenue from settlement on the wholesale market to pay any costs in relation to FTRs.[52] The Authority understands the use of auction revenue to firm revenue adequacy in this way is fairly unique among FTR markets in other jurisdictions. Any further review by the Authority will consider international FTR markets.

4.74 A noted trade-off from using auction revenue to fund FTRs, was that it would not always be available to fully offset the impact on transmission customers, who would also not be receiving LCE. However, the Authority at the time (2011) considered this impact to be a wealth transfer, and therefore did not consider it to have a negative efficiency effect. The direct relationship between transmission customers and FTR market, and the associated wealth transfer may not be as clear cut now as the 2011 decision suggests.

4.75 Revenue adequacy settings and revenue inadequacy targets are a key feature of the FTR market. Revenue adequacy settings directly influence the amount of FTRs made available by the FTR manager and this impacts the probability that an FTR holder will receive 100% of its pay-out.

4.76 Therefore, revenue adequacy requires finding a balance between managing the risk of underpayment of FTRs and making enough FTRs available for the FTR market to be viable and useful.[53]

4.77 However, in trying to achieve the primary objective of revenue inadequacy (which is to only occurs once in twelve months), the FTR manager would consequently increase the auction revenue through selling more FTRs (in order to reach the revenue adequacy target).The stated revenue adequacy objective is for revenue inadequacy to take place once every 12 months. Revenue inadequacy has happened less frequently. The lower frequency of revenue inadequacy may suggest the parameters used to set the inadequacy outcome are not correctly calibrated.

4.78 The Authority may need to reconsider the balance between efficiency benefits of the FTR market with the transfer of LCE to non-participants, particularly in light of the Authority's recent work on the efficiency benefits identified in revisiting the allocation of LCE.

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50 Revenue adequacy is when the FTR settlement amount (funding for FTRs) is sufficient to settle all FTR Hedge Values in full for a particular FTR period.

51 Paragraph 3.4.137, Electricity Authority, *Consultation Paper: Managing locational price risk: Proposed amendments to Code.* Available here: Consultation Paper (ea.govt.nz)

52 Paragraph 3.8.3, Electricity Authority, *Consultation Paper: Managing locational price risk: Proposed amendments to Code.* Available here: Consultation Paper (ea.govt.nz)

53 Paragraph 97. Electricity Commission, *Hedge Market Development – Issues and Option: Technical Paper, 18 July 2006*. Available here: Consult Doc Structure (ea.govt.nz))

Next steps

5.1 The Authority encourages the involvement of stakeholders in its decision-making process. Opportunities for stakeholder consultation will be provided in an iterative approach, and the Authority will engage with stakeholders on a regular basis. The Authority will continue to refine its observations following feedback from stakeholders.

5.2 FTRs were introduced in 2013 to help manage LPR, and to enhance retail and generation competition. The Authority's observations are that the link between FTRs and a growth in retail and generation competition is limited (Observation 1, 2 and 3). However, LPR continues to exist in the wholesale market. An alternative explanation could be that retail and generation competition would be less competitive without the presence of FTRs, and that the management of LPR through FTRs allows for a lower risk solution to the challenges of competition in a nodal price wholesale market.

5.3 The Authority observes that market solutions to managing LPR are limited. The ability of LPR to be managed through swaps on the ASX futures market is restricted to swaps between the Benmore and Otahuhu nodes, which covers some inter-island price separation risk, but does not cover intra-island risk. An alternate could be bilateral trades between market participants to cover LPR, however the Authority does not have evidence that there is a significant level of bilateral trading to cover LPR, and the presence of the FTR market may preclude this.

5.4 The FTR market may still be the best option to address unmitigable LPR. However, the Authority has observed some characteristics of the FTR market that warrant further investigation (Observations 4 – 11). These characteristics could warrant adjustment to the FTR market. These adjustments to the FTR market could take many forms:

(a) Improving access, if the Authority determines there are barriers to entry to the FTR market which prevent stakeholders participating in the FTR market, the Authority would consider improving access to information or enhanced training for new participants

(b) Changing the objective of the FTR market, if the Authority determines that the current FTR market is not accurately targeting locational price risk, the Authority may consider placing more attention in the FTR objective to the management of locational constraints

(c) Changing how the FTR market accesses LCE, if the Authority determines the use of LCE for the FTR market is excessive, the Authority may consider amending the FTR manager objective function.

(d) Changing who can access the FTR market, if the Authority determines the actions of some participants currently using the FTR market is not in the long-term benefit of consumers, the Authority may consider who is eligible in accessing the FTR market.

(e) If the Authority's observations on the operation of the FTR market are considered to be significant issues, the Authority may then consider how to address these concerns.

5.5 The Authority may also consider alternatives to the FTR market to manage LPR risk. These alternatives could be similar to those considered in the leadup to the introduction of the FTR market (for example LRA) or other alternatives.

5.6 The Authority's decisions will be guided by the long-term benefit of consumers. The options listed are indicative only and should not be interpreted as mutually exclusive or exhaustive. Stakeholders are invited to provide feedback on the initial range of solutions or/and suggest alternative solutions.

5.7 Any changes to the FTR market, by the nature of the long forward purchase of FTR products, may take some time to implement. Informational solutions would be quicker to implement than longer term structural changes.

5.8 Consideration of changes to the FTR market will take into account alternative uses of LCE. The Authority has consulted on the Settlement Residual Allocation Methodology (SRAM) as part of the Transmission Pricing Methodology. The SRAM can benefit grid users by providing a partial offset against the volatile (and unpredictable) transport component of nodal prices. The SRAM can be designed so that it provides a partial offset against this volatility. Therefore, the SRAM can be treated as a counterfactual to the use of LCE in the FTR market.

The Authority wants to hear from stakeholders

6.1 The Authority would like feedback from stakeholders on observations identified. The Authority welcomes submissions on the observation questions, and any supporting discussion points.

Observation 1: Changes in the make-up of renewable generation will see LPR continue to change over the next 10 years.

Q1	What is your view on how LPR might evolve over the next decade?
Q2	Do you see LPR as a genuine risk to your business? Why/why not?

Observation 2: Retail competition has increased over time, however it is difficult to determine the influence that FTRs have on retail competition.

Q3	What influence has the availability of FTRs had on your decision to compete for consumers?
Q4	What benefits do you see the FTR market providing in terms of consumer outcomes? Why/why not?

Observation 3: There has been no apparent impact on generator competition due to FTRs.

Q5	What influence has the availability of FTRs had on your generation investment decisions?
Q6	Has the FTR market allowed your business to build new generation plant in new geographic areas? Why/why not?

Observation 4: FTRs currently use an average of $5.29 million per month from LCE (~47% of total LCE) to settle.

Q7	Does the current use of LCE to support the settlement of the FTR market deliver the best outcomes for consumers? Why/why not?

Observation 5: Some parties may be consistently profiting from FTRs without a clear benefit to consumers.

Q8	Why do you think some FTR participants are profiting from FTRs more than others?

Observation 6: The LPR due to losses is highly correlated with energy prices while LPR due to constraints is not.

Q9	Is it for the benefit of consumers to use loss rentals, constraint rentals and auction income to support the settlement of the FTR market? Why/why not?

Observation 7: Many parties (particularly direct connect consumers and independent retailers) who are subject to LPR are not using the FTR market.

Q10	Why do you think organisations that are exposed to LPR are not participating in the FTR market (directly or indirectly)?
Q11	What do you think can be done to maximise the efficient use of LCE for the benefit of consumers?

Q12	Do you consider LPR to be an impediment to effective retail and generation competition? Why/why not?
Q13	How does the FTR market allow you to manage LPR? What non-FTR market tools do you use to manage LPR?
Q14	Are changes required to the FTR market for the long-term benefit of consumers? Why/why not?

Observation 8: FTRs tend to trade somewhat below ‘fair value.’

Q15	Do you agree with the view that FTRs are currently traded below ‘fair value’? If yes, why do they trade below fair value?
Q16	Should FTRs be traded at/closer to ‘fair value?’

Observation 9: Some features of the FTR market appear to be unintended and have no direct link to consumer benefit.

Q17	Are there other features of the FTR market that appear unintended or to have no clear consumer benefit?
Q18	Does the feature of the FTR market identified by the Authority negatively impact consumers? How?

Observation 10: The Financial Markets Authority does not regulate trading conduct in the FTR market.

Q19	Do you think there is a requirement for enhanced oversight of the FTR market?

Observation 11: Revenue adequacy settings of the FTR market contribute to the profitability of FTRs.

Q20	What are your views on speculators benefiting from the design of the FTR market?
Q21	What benefit does speculation provide to the FTR market, and what link does this provide to consumer benefit?

Other Authority workstreams considering LCE allocation

7.1 The Authority is undertaking a piece of work on the Transmission Pricing Settlement Residual Allocation Methodology that influences the allocation of LCE to the FTR market and to consumers.

Transmission Pricing Methodology (TPM) Settlement Residual Allocation Methodology (SRAM) workstream will not impact this review of the FTR LCE allocation

7.2 The TPM review of SRAM is a review of the methodology used to allocate residual LCE not used by the FTR market (and any auction income not required for the settlement of FTRs) to appropriate parties.

7.3 This project has been considered because any changes to the FTR market may only change the amount of residual LCE available to be allocated via the SRAM. Therefore, there are no conflicts that prevent each piece of work from progressing independently.