

FTR HUB REVIEW: COST BENEFIT ANALYSIS

OCTOBER 2026

IN-CONFIDENCE: ORGANISATION

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Executive summary

This document summarises the Cost-Benefit Analysis (CBA) undertaken by the FTR Manager for the 2026 FTR hub review. The review is a process required by the FTR Allocation Plan.

- In the previous step of this hub review, participants voted to nominate five new hubs to consider for addition, and one existing hub to consider for removal.
- This CBA used the previous method of assessing productive efficiency as well as a new supplementary measure as some of the voted-for hubs are associated with generation as well as retail.
- The CBA aims to demonstrate which additional hubs would have a positive cost-benefit. As such it needs to quantify benefits only to the point that they exceed costs: it does not estimate full market benefits.
- The outcome of this CBA is that the FTR Manager recommends to the Electricity Authority (Authority) the addition of five new hubs and the removal of none.

1.1 Overview

A key input to the CBA is the output of the previous stage of this hub review, being the nominated subset of hubs chosen through participant votes using a methodology prescribed in the FTR Allocation Plan.

Details of the 2026 hub review process leading up to this are available in the [consultation paper] and at ftr.co.nz/hub-consultation/.

The nominated subset of hubs are:

Table 1 – Nominated subset of hubs

Consider for	Hub	Settlement node
Addition	Manapouri (MAN)	MAN2201
	Marsden (MDN)	MDN2201
	Stratford (SFD)	SFD2201
	Tuai (TUI)	TUI1101
	Wairakei (WRK)	WRK2201
Removal	Redclyffe (RDF)	RDF2201

The nomination of the Redclyffe (RDF) hub for removal was determined to be conditional on the addition of the Tuai (TUI) hub.

There are currently eight hubs in the FTR market, so this hub review could potentially add five more, and remove one.

The analysis has been conducted by EMS as the FTR Manager service provider with input and feedback from the Clearing Manager (NZX), industry participants and Authority staff.

The FTR Allocation Plan requires that the FTR Manager, if one or more new FTR hubs are selected to be added, and a positive cost-benefit can be demonstrated, propose to the Authority a corresponding variation to the FTR Allocation Plan.

The last hub review was in 2017 and resulted in three FTR hubs being added to the then-existing five. The CBA was based on a productive efficiency calculation that assessed the benefits in retail competition and hence reduction in consumer price required to justify the costs of implementing the additional hubs, and then considered whether adding the new hubs could be expected to lead to at least the required reductions. The outcome was that expected benefits exceeded costs for all three of the nominated subset of hubs, which were recommended by the FTR Manager and approved by the Electricity Authority (Authority).

That productive efficiency analysis was developed by the Authority with the industry in 2011 – 2013 and was used as the basis for justifying previous hub additions in 2014 and 2017.

1.2 Costs

The FTR Manager has estimated its costs in supporting additional hubs, and has sought estimates from the Clearing Manager and participants, presented in the table below:

Table 2 – Total capital and operational costs (incremental)

		Number of hubs added		
	Source	1	2	3 to 5
Upfront capital costs	FTR Manager, Clearing Manager, Participants	$ 450,000	$ 40,000	$ 0
Operational costs per annum	FTR Manager, Clearing Manager, Participants	$ 45,000	$15,000	$ 0

Note that these costs are indicative and likely to change during the implementation phase. Costs have been aggregated for confidentiality purposes.

1.3 Benefits

We applied the tried and tested productive efficiency analysis approach to assessing benefits again this time. However, there are two relevant differences between this hub review and the last hub review in 2017:

Firstly, in the 2017 hub review the service provider and participant costs increased materially with each hub added. For 2026, as seen above, these costs are ‘front-loaded’ in that there are significant costs in adding the first hub, and a small additional cost in adding the second hub, with no additional costs for adding a third, fourth or fifth hub.

This means that if this CBA can justify adding any two hubs, then it will justify adding all five.

Secondly, in 2017 the nominated subset of hubs would allow access to large retail regions, supporting the appropriateness of the productive efficiency analysis used. In 2026, some of the nominated subset of hubs such as Manapouri (MAN) support smaller retail regions, and have clear generator as well as retail benefit. While the productive efficiency analysis remains appropriate for them, there was concern that it would not be sufficient to justify them. Further, the nominated Tuai (TUI) hub is very close to the existing Redclyffe (RDF) hub, and regional[1] productive efficiency analysis may not be granular enough to distinguish them. For these reasons we supplemented the productive efficiency analysis with an analysis of price difference volatility that the addition of a hub would help participants manage.

Before conducting the productive efficiency analysis, which is based on consumer benefit achievable through greater retail competition, we need to determine whether there is a retail competition issue in each nominated subset hub region. We assessed this using a number of standard metrics including the Herfindahl-Hirschman Index (HHI) as a commonly used measure of concentration, retailer count, observed switching rate and monthly retail charge. We assessed that for all five nominated subset hubs there is moderate market concentration, indicating that there is room for improvement in retail competition and hence the potential for productive efficiency gains in all the nominated subset hub regions.

We then conducted the productive efficiency analysis. A key metric is the annual cost reduction per ICP, and so per consumer, that would be required to justify the cost of adding each nominated subset hub, or combination of hubs. Adding all five hubs is well within bounds of what has been considered reasonable previously (19 cents compared to around $5). To support this, because of the 'front-loading' of costs onto the first two hubs added, we can consider a 'worst case' of adding the one or two hubs with the least benefit under this metric (the highest cost reduction required), i.e. see if the benefit of even the least-beneficial order of introducing new hubs exceeds the cost.

The only metric with a value materially higher than past productive efficiency gains considered reasonable is that of adding MAN as the only new hub (about $10). All other options, including adding MAN with one or more other hubs, and including adding all five hubs, fall well within those bounds. Thus, the addition of all five hubs passes the productive efficiency CBA.

Nevertheless, given the importance of generation as well as retail issues in this hub review, we have supplemented the productive efficiency analysis with a price difference volatility measure, that adds strong support to the two generation-based hubs Manapouri (MAN) and Wairakei (WRK), provides a measure of the value of adding Tuai (TUI), and adds material support to the other nominated subset hubs too.

1.4 Results

These results are summarised in Table 3 below. As the costs are so front-loaded with regard to the number of hubs added, these results are shown for a single hub only. Adding further hubs would significantly increase the benefit with minimal increase in cost.

[1] The data used to support the analysis is not available at sub-regional level.

Table 3 – Summary of required benefits for adding a single nominated subset hub

	Measure	MAN	MDN	SFD	TUI	WRK
Retail concentration	HHI, switching	Room for improvement in retail competition and hence potential productive efficiency gains, especially for SFD and MAN.				
Productive efficiency	Annual cost per ICP as single hub	$10	$0.27	$0.82	$0.96	$5.17
Price difference volatility	PV as proportion of value pa[2]	0.44%	0.92%	0.12%	1.78%	0.38%
Participants' advice	Mostly unquantified	Supported addition of all five nominated subset hubs				

The CBA supports adding all five nominated subset hubs.

The FTR Allocation Plan requires that the FTR Manager invite participants to advise their views on market benefits should hubs be added or removed. Responding participants support the inclusion of all five nominated subset hubs. No responding participant suggested not adding any of the nominated subset hubs. This supports the CBA conclusions on adding the nominated subset hubs.

As well as five additional hubs, the hub nominations included the Redclyffe (RDF) hub for removal. This was determined to be conditional on the addition of the Tuai (TUI) hub. The analysis has supported the addition of TUI. There are no identified costs but no identified benefits either, to removing the RDF hub. Our region-based productive efficiency analysis is not granular enough to differentiate between such close hubs. The price difference volatility between RDF and TUI, measured as value at risk average per annum is the lowest of the five nominated subset hubs – not unexpected for a low-capacity line – but still significant at some $5 million per annum. While participants support adding TUI, some suggested keeping RDF if TUI is added.

1.5 Recommendation

On the basis of this CBA, in accordance with the FTR Allocation Plan, the FTR Manager recommends that the Authority adds the five subset hubs nominated for addition: Manapouri (MAN), Marsden (MDN), Stratford (SFD), Tuai (TUI) and Wairakei (WRK), and does not remove any existing hubs.

[2] For one hub, averaged where two values

2 Introduction

2.1 Background

Energy Market Services (EMS), a business unit of Transpower, is the FTR Manager appointed by the Electricity Authority (Authority).

The FTR Allocation Plan requires that the FTR Manager conduct a regular process to offer FTR participants the possibility to add up to five new hubs, and to remove up to one existing hub[3].

Past hub reviews are summarised in section 2.4.

2.2 2026 hub review process timetable

The FTR Manager has been undertaking an FTR hub review in 2026[4]. The timetable below provides an overview of this process[5]. This cost-benefit analysis (CBA) document represents Step 10 of the sequence, the publication of the "final set" of hubs with accompanying CBA, as a basis for the Authority to determine hubs to be added or removed.

Table 4 – 2026 hub review process timetable

Sequence Ref. #	Process step	Indicative date	Other
1	FTRM informs Authority of intent to conduct hub consultation. FTRM prepares indicative costs for technical changes included.	2-Feb-26	Complete
2	Authority Responds to the FTRM information	17-Mar-26	Complete
3	FTR Manager to determine the hub long list	19-Mar-26	Complete
4	Hub Review Consultation 2026 call for nominations paper released	1-May-26	Complete
5	Deadline for hub nominations	1-June-26	Complete

[3] See *https://www.ftr.co.nz/ftr-manager-policies/ftr-allocation-plan/* sections 4.10 and 4.11.

[4] See *https://www.ftr.co.nz/hub-consultation/*

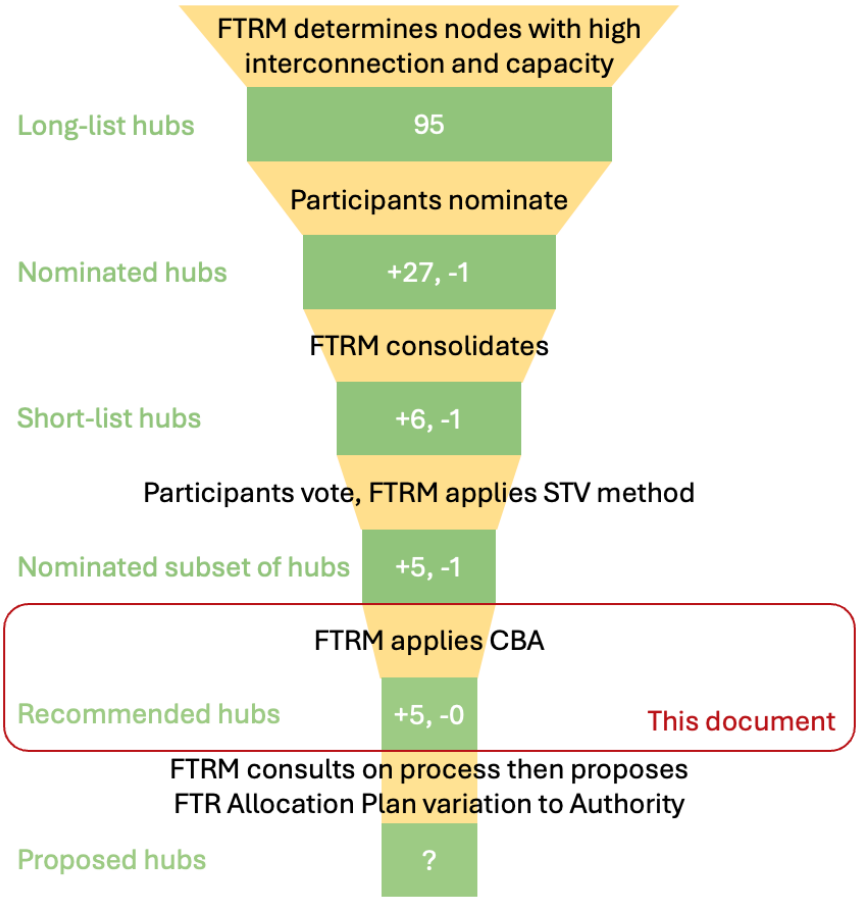
[5] Note that dates for the CBA completion, and FTR Allocation Plan consultation have been moved out by approximately one month since the previously communicated timetable

Sequence Ref. #	Process step	Indicative date	Other
6	Ranked short list published and voting requested	16-Jun-26	Complete
7	Deadline for voting on short list	23-Jun-26	Complete
8	STV Algorithm applied to determine ranked/prioritised short list suitable for CBA	8-Jul-26	Complete
9	Costs and Benefits Analysis (CBA) begun with participant input	16-Jul-26	Complete
10	FTR Manager creates a “final set” of hubs with accompanying CBA.	4-Sep-26	Complete
11	Any proposed variation to the Allocation Plan with additional or removed hubs released for formal consultation	29-Oct-26	In Progress
12	Deadline for Allocation plan submissions	12-Nov-26	
13	Publication of Allocation Plan if approved by Authority board.	10-Dec-26	
14	FTR Manager prepares a change request and seeks approval to implement the change to the system.	10-Dec-26	
15	FTR Manager begins technical changes to the system	TBC	

2.3 Hub review process overview

The hub review process involves progressive filtering from all available FTR grid nodes through to proposals for any new hubs, or the removal of existing hubs. The numbers indicate the number of hubs in the list at each stage.

Figure 1 – Summary of hub review process and terminology



We also use the term existing hubs, for those already in the FTR market as prescribed by the FTR Allocation Plan.

Further information on the 2026 hub review can be found at *ftr.co.nz/hub-consultation/* and in our FTR Allocation Plan - Consultation on proposed variation_FINAL.pdf

2.4 Past FTR hub reviews

The FTR market commenced in 2013 as a two-hub market, Benmore (BEN) and Otahuhu (OTA).

In parallel, the Authority ran its 'Within-island basis risk (WIBR)' work programme, which included development of a cost-benefit analysis (CBA) approach to evaluating new hub proposals. Consequent on this, the Authority instructed the FTR Manager to add the Haywards (HAY), Islington

(ISL) and Invercargill (INV) hubs from 2014, being the hubs with the highest net benefit as determined through WIBR.

WIBR involved the Authority's Locational Price Risk Technical Group (LPRTG) with its strong industry representation. In 2017 it was decided to involve FTR participants more directly by inviting them to propose new hubs and rank them, using a 'single transferrable vote' (STV) methodology to determine a short-list of nominated new hubs to take through to CBA. WIBR's CBA methodology was used (see section 6 below for more detail). Consequent on this, the Authority approved the development of three new FTR hubs at Whakamaru (WKM), Kikiwa (KIK) and Redclyffe (RDF) to be implemented from 2018: "*They will extend the ability to manage price risk to these locations, with consequent benefits for retail competition in downstream areas*"[6].

Since 2019, two hub consultations have been put on hold at the Authority's request due to the need to prioritise a wider FTR market review and manage the 2024 dry winter.

There are currently eight FTR hubs, as defined in section 2.2 of the extant FTR Allocation Plan 2018:

Table 5 – Existing hubs

Hub	Settlement node	Offered in Auctions from
Benmore (BEN)	BEN2201	June 2013
Otahuhu (OTA)	OTA2201	June 2013
Haywards (HAY)	HAY2201	November 2014
Islington (ISL)	ISL2201	November 2014
Invercargill (INV)	INV2201	November 2014
Whakamaru (WKM)	WKM2201	May 2018
Kikiwa (KIK)	KIK2201	May 2018
Redclyffe (RDF)	RDF2201	May 2018

In 2026, this hub review was commenced.

6 *ea.govt.nz/projects/all/ftr/consultation/financial-transmission-rights-development/*.

2.5 Nominated subset of hubs

The FTR Allocation Plan requires the FTR Manager to invite FTR participants to vote on their preferences for additional hubs using a single transferable vote (STV) method. For this review, this resulted in five hubs being nominated for consideration for addition, and one hub for consideration for removal being 'nominated' to progress to CBA.

The results of participant voting with the STV methodology applied are presented in Table 6 below:

Table 6 – Nominated subset of hubs

Consider for	Hub	Settlement node
Addition	Manapouri (MAN)	MAN2201
	Marsden (MDN)	MDN2201
	Stratford (SFD)	SFD2201
	Tuai (TUI)	TUI1101
	Wairakei (WRK)	WRK2201
Removal	Redclyffe (RDF)	RDF2201

The nomination of the RDF hub for consideration for removal was determined to be conditional on the addition of the TUI hub. That is, RDF would not be considered for removal unless it was determined that TUI would be added.

The existing and nominated subset of hubs are geographically illustrated in Appendix 1.

3 Cost benefit analysis (CBA) approach

It is assumed here that the reader is familiar with New Zealand's FTR market. If not, information can be found from the Authority at *ea.govt.nz/projects/all/ftr* and FTR Manager at *ftr.co.nz*.

The CBA aims to demonstrate which additional hubs would have a positive cost-benefit. As such it needs to quantify benefits only to the point that they exceed costs: it does not attempt to estimate full market benefits.

3.1 FTRs help manage locational price risk

The FTR market helps parties manage risk from the differences in spot prices between locations, referred to as locational price (or basis) risk.

The FTR market is one of the three key markets in the New Zealand hedge market, along with Futures and options exchange (currently ASX only) and the Over-the-counter (OTC) market. It is the only one of those three hedge markets that directly addresses locational price risk.

Locational price risk is material in New Zealand, as the wholesale market uses locational marginal pricing, and our geography leads to a long, stringy grid susceptible to loss- and constraint-based price impacts.

The FTR market helps to promote retail competition by encouraging retailers to compete for customers on a nationwide basis, as opposed to focusing primarily on regions close to where they own generation assets. This is because retail competition is linked to participation in the electricity wholesale market where one of the key factors has been the management of locational price risk. The FTR market currently enables the management of significant locational wholesale price risk, but risk remains where there is no FTR hub available, and this can affect retail competition.

The FTR market also helps generators, by improving their ability to manage the risk of selling their product remotely, and allows direct connect industry (that directly connect to the national grid rather than distribution companies' networks) to better manage their locational spot price risk when they purchase directly from the Clearing Manager.

3.2 Locational price risk trends

Looking forward, as the Authority notes: "As we transition to an increasingly renewables-based and decentralised electricity system, shifts in generation and demand patterns will lead to increased price volatility and locational price risk for market participants. This may necessitate changes to the number or location of FTR hubs. For example, new renewable generation built in areas outside of the current FTR grid could increase the likelihood of constraints in those areas or contribute to

greater price differences which increase locational price risk for retailers operating in these regions."[7]

The Authority's Market Development Advisory Group (MDAG)'s 2023 report "*Price discovery in a renewables-based electricity system - Final recommendations*"[8] provides some background:

- The increasing share of supply from intermittent sources will lead to more frequent fluctuations in the short-term balance between supply and demand. This physical trend will cause an increase in short-term price volatility in the spot market, with more frequent periods of very low and very high spot prices.
- To better understand the magnitude of this change, MDAG undertook simulation modelling […] The key insights from the modelling analysis are that spot price volatility is expected to increase significantly over time, especially between 2020 and 2035.
- Volatility measures for shorter-duration periods (e.g. hours, days, weeks) increase more than for longer periods (months or years). While longer-term weather effects (such as 'dry years') remain, the shorter-term weather 'noise' gets larger over time, driving up volatility ratios at the shorter end of the spectrum.

Locational price risk is driven by both losses and constraints. The value of losses is proportional to price, so increased price volatility directly increases the loss-based locational price risk. The MDAG modelling did not go to the level of intra-island transmission constraints, but these can be expected to increase too as intermittent generation results in more dynamic grid flows, and potentially with increased demand especially 'step changes' such as data centres.

3.3 Components of the CBA

The purpose of the CBA is to determine whether the benefits of adding or removing a nominated subset hub would exceed its costs. As the costs are known, it is not necessary to determine the full benefits, if one or some of the benefits exceed its costs.

Previous hub review CBAs have used a productive efficiency measure based on determining the productive efficiency gains in the retail sector required to cover costs, and considering whether it can be expected that that this would be achieved by FTRs enabling greater retail competition.

- **Retail competition measures** are presented in section 5.
- **Productive efficiency analysis** is presented in section 6.

However, in this hub review some of the nominated subset hubs have significant generation as well as retail impacts. MAN is the site of a major generation plant, although it connects into Southland through North Makarewa (NMA). Northland hubs including MDN were proposed by participants primarily for generation reasons, and WRK is part of the 'Wairakei ring' with significant generation, with more expected.

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[7] EA 2026 Review of the application of loss and constraint excess to the settlement of FTRs - Consultation paper – see *https://www.ea.govt.nz/projects/all/ftr/consultation/review-of-the-application-of-loss-and-constraint-excess-to-the-settlement-of-financial-transmission-rights/*

[8] See *https://www.ea.govt.nz/projects/all/pricing-in-a-renewables-based-electricity-system/*

Further, while productive efficiency analysis can be expected to justify a Hawkes Bay hub (as occurred with RDF in the 2017 hub review), it may not be sensitive enough to justify in effect shifting the Hawkes Bay hub from RDF to TUI.

We therefore introduce an additional CBA measure of locational price risk to estimate the benefits that would accrue from adding that hub:

- **Price difference volatility**, presented in section 7.

We initially planned to consider also constraint risk but determined that – for this CBA – it was unnecessary as productive efficiency plus price difference volatility turned out to be sufficient[9].

In addition, participants have provided their analysis of cost-benefits.

- **Participants' advice on benefits** is presented in 8.

Then, these four components are summarised together as:

- **Analysis results summary**, presented in section 9.

3.4 Key CBA parameters

Costs and prices are given in 2026 NZ dollars excluding GST.

The nominated subset hubs, should they be recommended by the FTR Manager and approved by the Authority for inclusion in the FTR Allocation Plan, are unlikely to start earlier than mid-2027. We have therefore assumed that for the purposes of present value analysis, both costs and benefits will start in calendar 2027.

This CBA models the costs and benefits of the preferred options over a period of 15 years from 2027 through 2041. This time horizon seeks to capture enough of the on-going costs and benefits after the initial development and implementation costs to provide a robust assessment of the hub implementation.

So that we can directly compare costs and benefits occurring at different points in time, we adopt a discount rate of 8% per annum to convert future costs and benefits to their present values. This reflects a public policy perspective for proposals that have mainly commercial costs and benefits, as recommended by the NZ Treasury[10] (who recommend also the use of 2% as a sensitivity test).

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[9] Price difference volatility is a quantitative measure looking backwards, but projecting forwards. Constraint risk is envisaged as a qualitative measure looking forward. Large locational price differences typically result from transmission constraints. Investment in transmission can take longer than in new load (especially 'step' loads such as data centres or new industry) or generation (especially solar). Further, transmission upgrades typically involve significant outages to build and commission. Therefore, future constraint risk can to a degree be qualitatively assessed from for example outage plans (up to about two years) and beyond that from Transpower's Transmission Planning Report or TPR, and a variety of sources can be used for demand and generation scenarios. While not needed for this hub review, we will consider such a measure if needed for the future hub reviews.

[10] The Treasury recommends 8% to assess proposals with *mainly commercial* costs and benefits, and 2% to assess proposals with mainly non-commercial costs and benefits. It recommends further that each proposal is sensitivity tested with the other discount rate: *https://www.treasury.govt.nz/information-and-services/public-sector-leadership/guidance/reporting-financial/discount-rates*.

The FTR Manager recognises that the cost of capital estimated by participants will vary, often dependant on the risk premium expectations of investors, but expects that any such differences will fall within the bounds of the discount rate used in this CBA.

Table 7 – Key CBA parameters

Parameter	Assumption
Currency	NZD 2026 excluding GST
Additional hubs active from	Assumed sometime during 2027
Horizon	15 years
Discount rate	8% per annum

3.5 Nominated subset hub regions

Some hubs can 'open up' regions to increased competition through allowing the locational price risk into or out of that region to be more effectively hedged. We are in practice limited in analysis to considering EMI regions[11], which is the level of aggregation of available data. The EMI data are grouped by distribution company regions, albeit that some distribution companies now cover several regions.

The mapping used is provided in the table below:

Table 8 – Nominated subset hub regions

Hub	Region	
MAN	38	Southland (The Power Company)
MDN	1	Bay of Islands (Top Energy)
	2	Whangarei and Kaipara (Northpower)
	3	Waitemata (Vector)
SFD	9	King Country (The Lines Company)
	19	Taranaki (Powerco)
	20	Whanganui (Powerco)
TUI	14	Tairawhiti and Wairoa (Firstlight Network)
	15	Hawke's Bay (Unison Networks)
	16	Central Hawke's Bay (Centralines)
WRK	13	Taupo (Unison Networks)

These regions are used for determining retail competition measures in section 5 and, with proportions applicable to each hub considered, for analysis of productive efficiency in section 6.

[11] Until winter 2026, EMI has been the Authority's Electricity Market Information platform. EMI is the primary source of electricity market time series and regional data sets used in this CBA. It divides New Zealand into forty regions, largely based on distribution network regions. The Authority has now migrated EMI to its new data and insights platform at *ea.govt.nz/data-and-insights/*.

4 Costs

4.1 Service provider and participant costs

The FTR Manager and Clearing Manager support the FTR market as service providers to the Authority.

To implement additional hubs, the FTR Manager would need to make changes to its FTR systems. The FTR Manager's costs to implement one to five additional hubs include requirements, testing, release management, communications, documentation, provider (including Resource Innovations) costs and contingencies.

In addition, there would be an increase in the FTR Manager's licence fee with Resource Innovations for the iHEDGE FTR software for implementing two or more additional hubs (from shifting to the next five-hub tranche in the FTR Manager's contract with Resource Innovations).

The Clearing Manager (NZX) has quoted for requirements, testing, release management for updates to clearing manager systems, as a fixed cost regardless of the amount of hubs that are to be added or removed.

Any Authority costs in implementing additional hubs or removing hubs, beyond those related to funding its service provider costs, are excluded from this CBA.

Participants also use their own software based FTR solutions and have business processes around them. Participants were asked to provide their costs of updating their systems and processes to accommodate the up to five additional hubs and removal of up to one hub[12]. Not all participants provided costs: we have assumed that all participants with material costs did provide them, but in case this is incorrect, we have considered the impact of doubling total participant costs as a sensitivity.

In order to preserve confidentiality, only the aggregate costs for the FTR Manager, Clearing Manager and Participants are included in this document.

The total of service provider and participant capital and operational costs, incrementally with respect to the number of hubs added, are presented in the table below.

[12] There has been debate in previous hub reviews as to whether participant costs should be included, given that participation in the FTR market is voluntary, and participants have raised it again in this hub review. While accepting that there are arguments both ways, we have as in previous hub reviews included participant costs for the CBA, but have included both reduced and increased costs as sensitivities.

For this hub review we considered also whether it would be possible to split participant costs between FTRs acquired for hedging and FTRs acquired for financial speculation, with a view to allowing for the costs of the former but not the latter. Many participants pointed out that this can be impossible to quantify, as FTRs form part of a hedge package, and can be held on behalf. We have not taken this further, but note related issue raised in footnote 19.

Table 9 – Total capital and operational costs (incremental)

	Source	Number of hubs added		
		1	2	3 to 5
Upfront capital costs	FTR Manager, Clearing Manager, Participants	$ 450,000	$ 40,000	$ 0
Operational costs per annum	FTR Manager, Clearing Manager, Participants	$ 45,000	$15,000	$ 0

4.2 Present value costs

Present value is used to determine the present-day value of an amount (measured in dollars) that is received at a future date. The present value can then be annualised, providing a basis of comparison with other annualised amounts, such as potential consumer benefit. The present value of service provider and participant costs, and its annualised equivalent, are presented in 10 below:

Table 10 – Total present value costs (incremental)

	Source	Number of additional hubs		
		1	2	3 to 5
Present value costs	TOTAL	**$ 836,000**	**$ 169,000**	**$ 0**
	Annualised 15 years	**$ 98,000**	**$ 20,000**	**$ 0**

There are no reported costs (or cost savings) related to the removal of a hub.

5 Retail competition measures

The benefits of encouraging retail competition depend on the degree to which retail competition already exists.

We have considered a number of metrics for this and selected[13]:

- HHI as a commonly used measure of concentration, lower the better, with 1500 considered the threshold for effective competition, and 1500 to 2500 as moderate market concentration.[14]
- Retailer count, becoming a less useful measure as more small retailers enter the market.
- Switching rate, which we take as per ICP[15] over the last 12 months
- Monthly retail charge, for which there is imperfect data. We have taken the total monthly bill less the network monthly charge for standard (rather than low) users.

We are restricted by data availability. In particular, the most granular we can get is average per ICP per region. This is not perfect as connections vary significantly in capacity and hence volume and value, but is a useful approximation, and the best available from the data. As some of our hub regions span multiple distributor regions (see Table 12), and one cannot meaningfully average these metrics across regions, we have re-created the measures from EMI's component regional ICP data.

This gives the measures presented in Table 111 below:

Table 11 – Retail competition indicators

	HHI	Retailer count	Switching rate pa	Monthly retail charge
MAN	2150	15	4.0%	$ 160
MDN	1750	29	5.9%	$ 150
SFD	2000	19	4.1%	$ 120
TUI	1650	20	6.8%	$ 160
WRK	1750	20	5.0%	$ 150

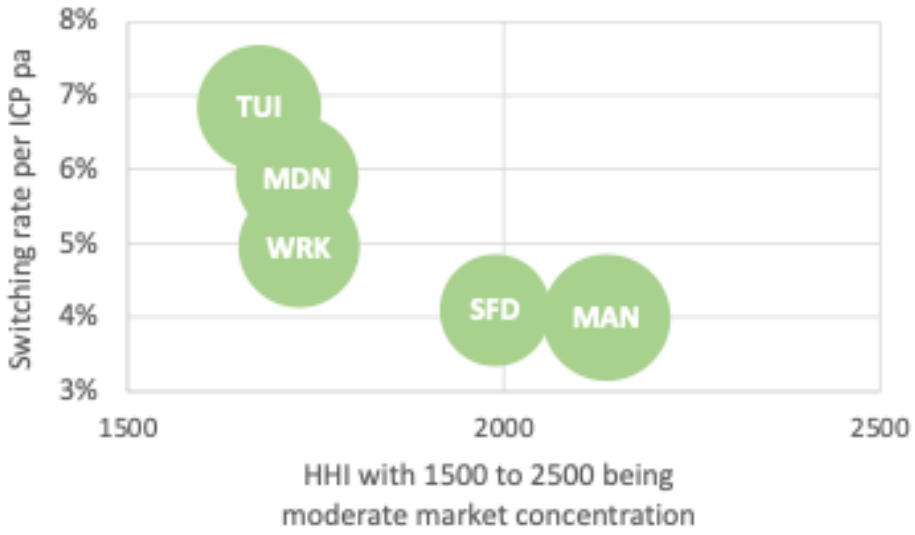
[13] One useful additional set of data used in 2017 was 'Annual consumer savings available from switching' but unfortunately those data are no longer available.

[14] The Herfindahl-Hirschman Index is calculated by squaring each retailer's market share percentage (expressed as a number 0 to 100) and summing the results, yielding a score from near zero to 10,000.

[15] Installation Control Point, being a point of connection where an electricity consumer connects to the distribution network.

Figure 2 plots these results using the HHI and switching rate measures, with the size of the bubbles indicating the monthly retail charge:

Figure 2 – Retail competition indicators



We see that these HHIs are all in the 1500 to 2500 range of moderate market concentration, and switching rates lower in some regions, indicating that there is room for improvement in retail competition and hence potential productive efficiency gains in all the nominated subset hub regions, but especially so for SFD and MAN.

6 Analysis of productive efficiency

The previous section has demonstrated that there is scope for, and hence benefits to, improving retail competition in all the nominated subset hub regions.

There are two primary methods of measuring the benefit required to support the addition of new hubs: allocative efficiency and productive efficiency. Allocative efficiency aims to measure the value of inefficiency in the market that prevents parties from consuming as much electricity as they would prefer, while productive efficiency measures the market inefficiency that prevents production from taking place at the lowest possible cost. An economy that achieves productive efficiency is also (normally) operating with technological and managerial efficiency in achieving near perfect competition. As competition approaches this point, profit is reduced as price nears marginal cost.

Because allocative efficiency benefits (reducing the dead weight loss) are likely to be second-order, they are outside the scope of this CBA. FTRs can also enhance dynamic (or investment) efficiency through enabling investment in locations that would otherwise have too great a locational price risk, but we have not attempted to address that either in this CBA.

In this analysis, we focus on productive efficiency. Increased competition in the retail market is enabled through lower risk in the wholesale market provided through additional hubs. For firms to remain competitive, and thus remain in the market, they must seek to reduce production cost as the retail price drops due to competition. Over the longer term, innovation is a key driver for this change, and the results are both lower costs for retailers, and lower power prices for consumers.

The productive efficiency method for measuring benefit of additional hubs has been used in (and developed from) previous hub reviews, as noted in section 0. The productive efficiency method presents an indication of the required fall in:

- The annual cost per ICP measured at each of the nominated subset hub regions
- The percentage share of retail operational cost (per customer or ICP).

The productive efficiency methodology is detailed in Appendix 2.

6.1 Nominated subset hub regions

Nominated subset hub regions were introduced in section 0.

As the number of hubs increases, it becomes less clear that whole rather than part regions are directly affected by a proposed new hub. The Southland region is already served, via North Makarewa, by the existing INV FTR hub. A MAN hub is expected to add some but little productive efficiency benefit to that region, so we have used 25% proportion for this region. There are arguments that similar concerns apply to other regions: for those we have used a 'base case' of 100% but explored other proportions as sensitivities in section 9.2. The base case proportions used are listed in the table below:

Table 12 – Nominated subset hub region proportions

Hub	Region		Proportion
MAN	38	Southland (The Power Company)	25%
MDN	1	Bay of Islands (Top Energy)	100%
	2	Whangarei and Kaipara (Northpower)	100%
	3	Waitemata (Vector)	100%
SFD	9	King Country (The Lines Company)	100%
	19	Taranaki (Powerco)	100%
	20	Whanganui (Powerco)	100%
TUI	14	Tairawhiti and Wairoa (Firstlight Network)	100%
	15	Hawke's Bay (Unison Networks)	100%
	16	Central Hawke's Bay (Centralines)	100%
WRK	13	Taupo (Unison Networks)	100%

6.2 Productive efficiency analysis results

The required fall in the percentage share of retail operational cost represents the retail electricity price reduction in the region affected by each of the additional hubs that is required to achieve a net positive benefit, and a preferential market investment. The ICP numbers in the table below are adjusted by the proportions in the table above before summation. The percentage values in the table below are the reduction required in the retail component of the average annual consumer electricity bill. Each of the five nominated subset hubs demonstrate that a relatively small competitive effect is required to support adding the hub to the FTR market.

Table 13 – Productive efficiency analysis results

	Number of additional hubs		
	1	2	3 to 5
Annualised incremental present value	$ 98,000	$ 20,000	$ 0

Hub	ICPs	Annual cost per ICP		
MAN	9,606	$ 9.98	$ 2.05	-
MDN	367,009	$ 0.27	$ 0.05	-
SFD	119,245	$ 0.82	$ 0.16	-
TUI	102,095	$ 0.96	$ 0.19	-
WRK	18,881	$ 5.17	$ 1.04	-
All 5	**616,836**			**$ 0.19**

Hub	ICPs	% share of retail operational cost		
MAN	9,606	3.98%	0.818%	-
MDN	367,009	0.11%	0.021%	-
SFD	119,245	0.33%	0.066%	-
TUI	102,095	0.38%	0.077%	-
WRK	18,881	2.06%	0.416%	-
All 5	**616,836**			**0.07%**

If we look at these productive efficiency results alone, then we see that:

- MDN would be the hub of choice should we add one hub (marked in green)
- MDN and SFD would be the hubs of choice should we add two hubs (marked in green)
- If we add two hubs then we should add all five hubs, as there is no incremental cost in adding the other three hubs, but material benefits.

As a check, the "All 5" hubs added result presented in the table above is based on amalgamating the five nominated subset hub regions and performing the same calculations, indicating that if all five nominated subset hubs were added irrespective of order, the metrics are low – only 19 cents and 0.07% – and hence strongly supportive of adding all hubs.

As described above, in past hub review CBAs we have not calculated the full efficiency benefit, but only the productive efficiency gains required, i.e. the annual reduction in retail costs required per ICP to justify the costs of adding the extra hub(s). The productive efficiency metrics calculated in this CBA are consistent with, or better than, the same metrics used to support the addition of what are now 'existing' hubs in past hub reviews, as shown in the table below:

Table 14 – Past productive efficiency gains considered justifiable

Hub	Year of hub review	Annual reduction in retail costs required per ICP	Adjusted to 2026 dollars
WKM	2017	$ 0.24	$0.33
HAY	2014	$ 1.14	$1.60
KIK	2017	$ 1.23	$1.67
ISL	2014	$ 1.35	$1.89
RDF	2017	$ 2.13	$2.90
INV	2014	$ 3.58	$5.02

Comparing the productive efficiency metrics in this review to what has been considered reasonable previously, we see that:

- Adding all five hubs is well within bounds (19 cents compared to about $5)
- Adding MDN, SFD or TUI as a single hub would be well within bounds (under $1)
- Adding just WRK as a single hub would be close to those bounds ($5 rounded)
- Adding just MAN as a single hub would be about double those bounds ($10 rounded).

The last result, for MAN, needs to be put in the context that:

- It is for adding MAN as the only hub: added as the third, fourth or fifth its productive efficiency benefits would obviously exceed the zero marginal costs
- $10 (or higher) could well have been considered reasonable in past review – this was not tested.

Nevertheless, MAN is a primarily a generation rather than retail node, and the 25% proportion used may be an over-estimate, so we can 'red-flag' that result.

[16] From the Reserve Bank of NZ *rbnz.govt.nz/monetary-policy/about-monetary-policy/inflation-calculator*: e.g. "General (CPI) that cost $3.58 in 2014 Q4 would cost $5.02 in 2026 Q4"

7 Analysis of price difference volatility

Since the primary purpose of FTRs is to manage locational price risk, measures of price difference volatility can provide a measure of the benefit of adding a new hub. We can readily measure the historical price volatility between a nominated subset hub and its nearest existing hub(s). Low volatility would imply a low benefit, as most of the hedge value of an FTR to the new hub could be achieved with an FTR to that nearby existing hub. Conversely, high volatility would imply a high benefit of the new hub. In doing so we need to acknowledge that:

- Past volatility is only indicative of future volatility. While we generally expect volatility to increase as our generation becomes more intermittent, it could across some paths decrease through for example transmission investment to relieve a constraint.
- Volatility is only a risk to the degree that it is unpredictable, and some volatility is at least in part predictable, for example when prices are affected by a planned outage.

If we already had FTR hubs as nominated, we could use FTR auction price as an indicator of the degree to which FTR participants anticipated forward risk, but of course in this case we do not.

For each nominated subset hub, we have assessed the nearest existing hub(s) as indicated in the table below[17]:

- MAN, MDN and TUI are in effect (at the FTR level) radial spurs off existing hubs: INV, OTA and RDF respectively.
- SFD is strongly connected through the 220kV network northwards to Huntly (HLY) which is electrically close to OTA, and southwards to Bunnythorpe (BPE) with is electrically close to HAY.
- WRK is part of the so-called Wairakei ring, strongly connected northwards to WKM and southwards to BPE with is electrically close to HAY.
- We choose a direction according to the usual price gradient as the path.

[17] See Transpower's North Island Power System (NIPS) diagram *here*, and SIPS *here*.

Table 15 – Choice of hub paths to estimate price difference volatility

Nominated subset hub		Nearest existing hub(s)	Path	Point-to-point indicative capacity[18]
Manapouri	MAN2201	INV2201	MAN-INV	562 MW
Marsden	MDN2201	OTA2201	OTA-MDN	441 MW
Stratford	SFD2201	OTA2201	SFD-OTA	1045 MW
		HAY2201	SFD-HAY	655 MW
Tuai	TUI1101	RDF2201	RDF-TUI	113 MW
Wairakei	WRK2201	WKM2201	WRK-WKM	1382 MW
		HAY2201	WRK-HAY	771 MW

For historical analysis, we have chosen a period of the last five years. From the last five years of final price data for these hubs, we can determine the locational price difference at a monthly level, to coincide with FTR Periods and align with market settlement which is typically monthly. This provides a time series of locational price difference values (the differences between monthly average price at the two hubs), a measure of the actual locational price volatility that an FTR participant may be seeking to manage (and corresponding to the value per MW of an Obligation FTR for the specified path).

For the volume at risk, we have taken the point-to-point indicative capacity of the FTR Grid as an approximation to the actual capacity which might vary day by day and trading period by trading period[19].

The values calculated in this way are presented in Table 16 below[20].

[18] From FTR Manager's analysis 2026

[19] This capacity approximates an upper bound, to reflect hedge rather than speculative values. Theoretically, it should be limited to capacity usage, which could be estimated from grid flows or the load and/or generation in the region. This refinement would not affect the results of this CBA, but should be considered for future hub reviews.

[20] The value at risk average pa in the right-hand column is calculated as:

- For paths with a positive price difference for every month in the five-year period, for example MAN with the MAN-INV path, the value is simply 12 times the average.
- For paths with some positive and some negative monthly price differences, for example TUI with the RDF-TUI path, the value is calculated as the sum of all positive month values minus the sum of all negative month values, divided by the number of years (5).

The component values have not been time-discounted, which is considered adequate for this high-level analysis and short horizon

Table 16 – Value of price difference volatility, last five years

Hub	Path	Maximum monthly value	Minimum monthly value	Average monthly value	Standard deviation	Value at risk average pa
MAN	MAN-INV	$M 6.4	$M 0.0	$M 1.8	$M 1.3	$M 22
MDN	OTA-MDN	$M 3.2	$M 0.0	$M 0.9	$M 0.6	$M 10
SFD	SFD-OTA	$M 17.4	$M 0.3	$M 6.9	$M 4.0	$M 82
	SFD-HAY	$M 17.3	$M -2.1	$M 0.8	$M 3.2	$M 12
TUI	RDF-TUI	$M 6.7	$M -2.0	$M -0.1	$M 1.0	$M 5
WRK	WRK-WKM	$M 6.7	$M 0.1	$M 1.6	$M 1.2	$M 19
	WRK-HAY	$M 26.1	$M -4.8	$M 1.5	$M 5.0	$M 36

These values, measured in $ million per month or year, are clearly much larger than the costs annualised at around $98,000 for the first hub, $118,000 total for two to five hubs.

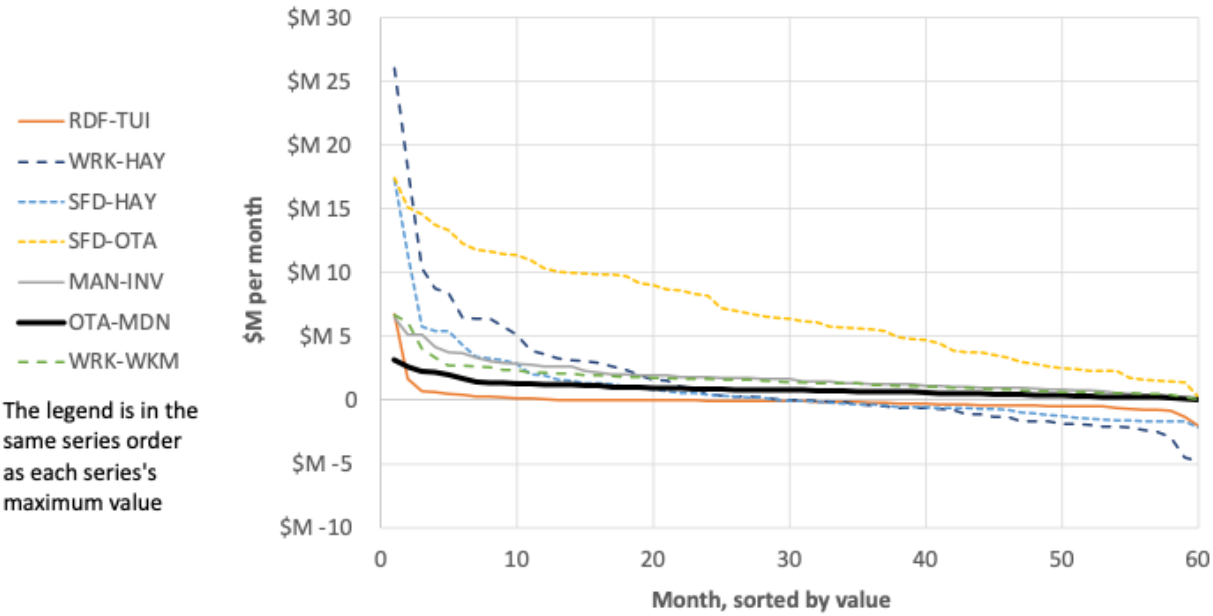
To indicate whether or not there is a systemic increase or decrease of volatility during the last five years, we can consider the 'price trend' measured as the correlation of monthly value with time over those five years: positive values indicate volatility increasing over time, negative decreasing. We can see in the table below that while in some cases the trend in volatility is downwards, the trend is small (close to zero) and in all cases the month of maximum value is in the most recent half of the period. This indicates that – from the data alone – there is no clear reason to dismiss historical volatility as an indicator of future volatility.

Table 17 – Trends in price difference volatility, last five years

Hub	Path	Price trend	Month of maximum value
MAN	MAN-INV	-0.03	August 2024
MDN	OTA-MDN	+0.16	June 2024
SFD	SFD-OTA	+0.26	August 2024
	SFD-HAY	-0.17	August 2024
TUI	RDF-TUI	-0.08	May 2024
WRK	WRK-WKM	-0.17	February 2025
	WRK-HAY	-0.26	August 2024

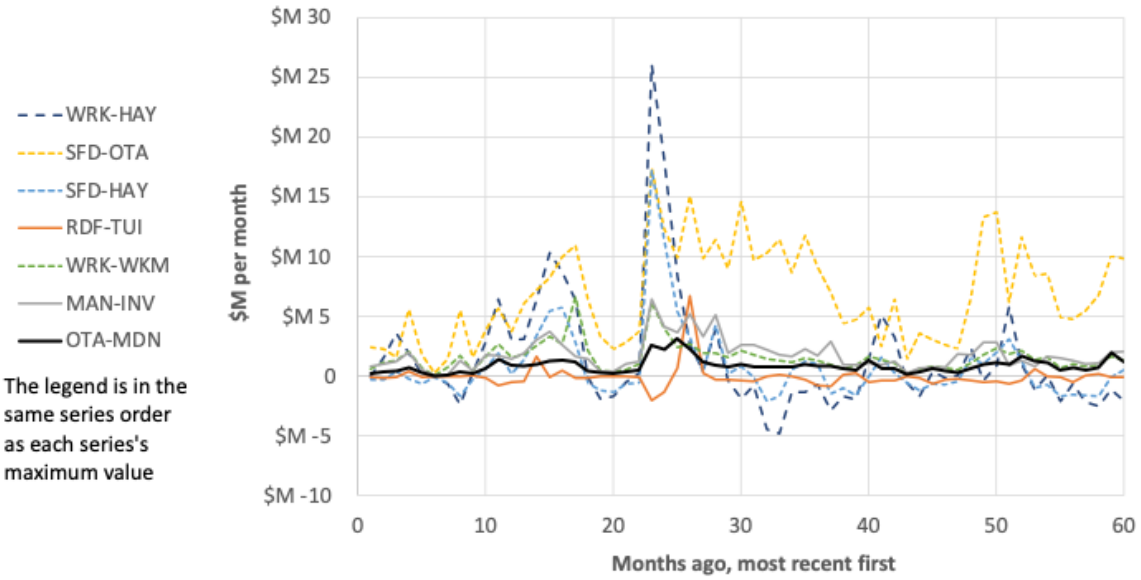
Sorting the monthly results for the last five years by value for each path gives the results shown in the figure below:

Figure 3 – Historical monthly price difference values, last five years, sorted



The same data with the same series order and formats are presented in the figure. While confused, it illustrates that there has been material volatility:

Figure 4 – Historical monthly price difference values, last five years, ordered



Recall that we are measuring the volatility in price differentials, but not locational price risk directly. Nevertheless, we can take a similar approach for productive efficiency analysis, which is to ask what percentage of that value would correspond to the cost of the investment, and is that reasonable?

This is presented in the table below[21]. For SFD and WRK, which have two nearby existing hubs, one northward and one southward, the 'max' adds their values, and the 'min' takes their difference.

Table 18 – Present value (PV) as proportion of value per annum (pa)

	Number of additional hubs		
	1	2	3 to 5
Annualised incremental PV	$ 98,000	$ 20,000	$ 0

Hub	Value pa	PV as proportion of value pa		
MAN	$M 22	0.44%	0.09%	-
MDN	$M 10	0.92%	0.19%	-
SFD max	$M 94	0.10%	0.02%	-
SFD min	$M 70	0.14%	0.03%	-
TUI	$M 5	1.78%	0.37%	-
WRK max	$M 55	0.17%	0.04%	-
WRK min	$M 17	0.58%	0.12%	-

Low present value as proportion of value per annum signifies increased value of a hub in that region.

For MAN for example, this indicates that even if:

- Only 30% of the volatility is unpredictable and therefore a risk
- Availability of a hub and therefore FTRs can only cover 30% of that risk
- Only 10% of that risk management translates into consumer benefit
- Which multiplies up to about 1% ...

… then that would be greater than the cost of adding MAN as the first hub (0.4%) or second hub (0.1%), even without considering the minimal costs of adding it as a third, fourth or fifth hub. All metrics are below 2% for a single new hub, below half a percent for a second hub, and vanish for three to five hubs.

[21] The annualised incremental PV (present value) is the sum of capital and operational (opex) costs annualised over the 15 year horizon at the 8% per annum discount rate.

8 Participants' advice on benefits

The FTR Allocation Plan requires that the FTR Manager invite participants to advise their costs and views on market benefits should hubs be added or removed. The FTR Manager requested in early July 2026 that participants provide costs and benefits associated with the possible introduction of the five nominated subset hubs, and possible removal of RDF.

The costs components are covered in section 4.1. This section covers participants' views on benefits. Some views related to the choice of which hubs to nominate, which has now been done through the STV voting process, so we have not included such comments here.

Some responding participants considered their return as confidential, so we have treated all returns as confidential.

We have therefore summarised and paraphrased participant views on overall benefits below:

- The addition of the five prioritised hubs delivers clear benefits under each efficiency limb (productive, allocative and dynamic). New hubs extend locational price risk coverage to regions where locational price risk cannot currently be hedged efficiently, reducing the risk premium embedded in retail and wholesale contracts.
- Adding new hubs is appropriate considering the rapidly evolving nature of the electricity market. The costs difference associated with adding one or many hubs is negligible. Therefore, any new hubs that help manage current and future grid constraint issues (due to increased generation investment or retail risk) should be seriously considered. We support all five hubs.
- As the Authority has itself observed, FTRs enhance competition in the retail and hedge markets by enabling participants to compete for customers nationally rather than only near their own generation; additional hubs directly extend that coverage and support efficient entry and investment in new generation through the energy transition. These benefits accrue market-wide over the full ten-year horizon.
- The positive benefit the FTR market has had on retail competition is difficult to overstate. On many measures, it has been more important than the ASX market-making scheme in allowing independent retailers to access competitively priced hedges. Independent retailers cannot manage risk internally in the same way as a gentailer and often need to buy hedges from the same gentailers against which they compete for customers.
- FTR hub expansion could reduce retail electricity prices by 0.25-0.50 percent, worth approximately NZD 12-24 million annually or NZD 120-240 million over 10 years to household consumers alone. We should proceed without delay to implement all proposed new FTR hubs.

Participants commented also on the interconnectedness of decisions on the TUI, RDF and WRK hubs, expressing varying ideas as to how the FTR hub arrangement could be configured:

- If TUI is added and RDF is removed, then WRK must be added. Wairakei ring constraints are one of the biggest transmission issues in the electricity market, and something which is likely to worsen as new generation is built in that area. Currently Wairakei ring risks can be

managed using FTRs that include the RDF hub. The fact that adding TUI will remove RDF means that the addition of TUI must also result in the addition of the WRK hub.

- Replacement of the RDF hub with TUI may necessitate some participants involuntarily needing to switch to using a hub that may have less benefit to them than their existing RDF use.
- We question the effects of removing RDF hub in favour of TUI with regards to reduced volume availability due to weaker grid connection, competition effects of having a hub with a single generator participant supplying it, and effectiveness of hedge cover for the Napier/Hastings area balanced against cover for Gisborne.
- We propose multiple hubs FHL [Fernhill, just south of RDF], TUI and RDF for cohesive representation

In conclusion, responding participants support the inclusion of all five nominated subset hubs with some questioning the removal of RDF. No responding participant suggested not adding any of the nominated subset hubs.

9 Analysis results

As noted above, the CBA does not need to determine the full benefits if enough benefits 'stack up' to justify the costs. In previous hub reviews, the productive efficiency approach (section 6) has been sufficient, and numerically it is for this hub review too.

However, the productive efficiency approach may not be considered so appropriate to generation-based hubs nor to differentiate between close retail-based hubs such as RDF and TUI, so we introduced consideration of price difference volatility (section 7) as a complementary metric. In addition, as required by the FTR Allocation Plan, we have considered participants' advice on benefits (section 8).

9.1 Addition of hubs

The required benefits for adding the nominated subset hubs are summarised in the table below. Green signifies greater justification for that notified hub being added as a single hub, red means lesser, orange in-between:

Table 19 – Summary of required benefits for adding a single nominated subset hub

	Measure	MAN	MDN	SFD	TUI	WRK
Retail concentration	HHI, switching	Room for improvement in retail competition and hence potential productive efficiency gains, especially for SFD and MAN.				
Productive efficiency	Annual cost per ICP as single hub	$10	$0.27	$0.82	$0.96	$5.17
Price difference volatility	PV as proportion of value pa[22]	0.44%	0.92%	0.12%	1.78%	0.38%
Participants' advice	Mostly unquantified	Supported addition of all five nominated subset hubs				

The analysis supports adding all five hubs nominated for addition.

- This can be supported on productive efficiency analysis alone, as in previous hub reviews, albeit with reservations regarding MAN as a single hub. All other options, including adding MAN or WRK with other hubs, and including adding all five hubs at 19 cents, fall well within the bounds considered reasonable in past hub reviews. Note that the productive efficiency benefit tabulated here is for the 'worst case' of adding only that hub. When added with other hubs, productive efficiency benefits are much higher, and annual costs per ICP much lower.

[22] For one hub, averaged where two values

- Given the importance of generation as well as retail issues in this hub review, we have supplemented the productive efficiency analysis with a price difference volatility measure, that adds additional strong support to the two generation-based hubs MAN and WRK and adds lesser material support to the other hubs too.
- Participants support adding all five nominated subset hubs.

The metrics used in this CBA strongly support the above conclusion, so we consider them robust, subject to sensitivity analysis.

9.2 Sensitivity analysis

Four issues have been noted above as contenders for sensitivity analysis:

- Discount rate
- Decreasing participant costs
- Increasing participant costs
- Adjusting regional proportions.

The first two sensitivities would increase the benefit and so make the case for adding the five hubs even stronger:

- Using a 2% rather than 8% per annum discount rate as the Treasury recommends would reduce annualised costs from around $98,000 and $20,000 for the first and second hub to around $80,000 and $18,000 respectively.
- Removing participant costs, on the basis that participation in the FTR market is voluntary (as was suggested in participant consultation), would reduce annualised costs from around $98,000 for the first hub to around $57,000 and make no difference to the second and subsequent hub costs, which reflect FTR Manager costs.

The third sensitivity of increasing participant costs obviously increases costs without changing the benefit, but not by enough to impact our conclusions. We considered doubling reported participant capital and operating costs, to illustrate a consequence if our assumption that all participants with material costs did provide them is incorrect. This has a material effect, increasing the present value costs and hence the required benefit by close to 50%. This increases our required productive efficiency metric for adding all five hubs: annual cost per ICP from 19 cents to 25 cents, and percentage share of retail operational cost from 0.07% to 0.10%, but both remain very low.

The fourth sensitivity relates to Adjusting regional proportions. As noted in section 6.1, using whole EMI regions risks over-estimating productive efficiency benefits where parts of those regions may already have been capturing some productive efficiency benefits resulting from existing FTR hubs. The following table considers a range of sensitivities to the proportions of a region assumed in the baseline analysis:

Table 20 – Sensitivity of overall results to regional proportions used

Hub	Regions included		*ICPs*	Baseline	Sensitivities	
MAN	38	Southland	*38,424*	25%	50%	10%
			ICPs	*9,606*	*19,212*	*3,842*
			Total annual cost per ICP	**$ 0.19**	**$ 0.18**	**$ 0.19**
MDN	1	Bay of Islands	*34,934*	100%	100%	100%
	2	Whangarei and Kaipara	*63,822*	100%	100%	100%
	3	Waitemata	*268,253*	100%	50%	0%
			ICPs	*367,009*	*232,883*	*98,756*
			Total annual cost per ICP	**$ 0.19**	**$ 0.24**	**$ 0.33**
SFD	9	King Country	*24,241*	100%	50%	0%
	19	Taranaki	*61,490*	100%	100%	100%
	20	Whanganui	*33,514*	100%	100%	100%
			ICPs	*119,245*	*107,125*	*95,004*
			Total annual cost per ICP	**$ 0.19**	**$ 0.19**	**$ 0.19**
TUI	14	Tairawhiti and Wairoa	*26,216*	100%	100%	100%
	15	Hawke's Bay	*66,893*	100%	100%	0%
	16	Central Hawke's Bay	*8,986*	100%	0%	0%
			ICPs	*102,095*	*93,109*	*26,216*
			Total annual cost per ICP	**$ 0.19**	**$ 0.19**	**$ 0.21**
WRK	13	Taupo	*18,881*	100%	50%	25%
			ICPs	*18,881*	*9,441*	*4,720*
			Total annual cost per ICP	**$ 0.19**	**$ 0.19**	**$ 0.19**

As can be seen, all sensitivities tested are strongly supportive of the overall conclusion that the analysis supports adding all five of the nominated subset hubs. The worst test result is excluding Waitemata from the MDN regions (not surprisingly with that many ICPs in Waitemata) which increases the total annual cost per ICP across all hubs from 19 cents to 33 cents, still well under the $5+ considered reasonable.

9.3 Removal of hubs

One hub, RDF, was nominated for consideration for removal conditional on the addition of the TUI hub. The addition of the TUI hub is supported as above, so the removal of the RDF hub needs to be considered.

On the removal of the RDF hub given that TUI is added, there are no identified costs but no identified benefits either. Our region-based productive efficiency analysis is not granular enough to differentiate between such close hubs. The price difference volatility between RDF and TUI, measured as value at risk average per annum is the lowest of the five nominated subset hubs – not unexpected for a low-capacity line – but still significant at some $5 million per annum.

While participants support adding TUI, some suggested keeping RDF if TUI is added.

FTRs are awarded through progressive auctions up to two years or more before the FTR Period, which is a calendar month. As at the month before a hub is ‘removed’, FTRs for that hub (as source

or sink) for that FTR Period will already have been awarded, up to about two years ahead. Those FTR holders' rights to FTR settlement but also to trading that FTR through assignments or reconfiguration auctions need to be honoured. Thus, if TUI was added and RDF removed, FTR service providers and participants would need to work with both hubs for an overlap period of some two years.

We conclude that there is no net benefit in removing RDF.

10 Conclusions and recommendations

The FTR Allocation Plan requires that the FTR Manager, if one or more new FTR hubs are selected to be added, and a positive cost-benefit can be demonstrated, propose to the Authority a corresponding variation to sections 2.2 and 2.3 of the FTR Allocation Plan.

10.1 Conclusions

It is concluded that the five nominated subset additional hubs of Manapouri (MAN), Marsden (MDN), Stratford (SFD), Tuai (TUI) and Wairakei (WRK) should be added as FTR hubs, as the benefits of doing so clearly exceed the costs.

The cost-benefit analysis is practically silent on the removal of Redclyffe (RDF): while there is no cost in doing so, there is no clear benefit either. RDF would need to remain as an FTR hub in auctions for two years even if scheduled for removal, so participants and service providers would have to manage both RDF and TUI hubs during this period.

10.2 Recommendations

The FTR Manager recommends that the following five hubs are added to the FTR market.

The FTR Allocation Plan needs to include not only the hubs to be added, but also the month from which they will be offered in FTR auctions from. The FTR Manager recommends October 2027 as achievable from an FTR system change perspective, noting the Authority's recent decision to revoke Schedule 14.3 with the Code amendment coming into effect on 1 October 2027[23].

Table 21 – Recommended hubs to add to the FTR market

Hub	Settlement Node	Offered in Auctions from:
Manapouri (MAN)	MAN2201	October 2027
Marsden (MDN)	MDN2201	October 2027
Stratford (SFD)	SFD2201	October 2027
Tuai (TUI)	TUI1101	October 2027
Wairakei (WRK)	WRK2201	October 2027

It is further recommended that no existing hubs are removed from the FTR market.

[23] More detail on this is provided in the FTR Manager's consultation on it proposed variation to the FTR Allocation Plan, October 2026.

11 Appendix 1: FTR hub maps




South Island
Existing
KIK Kikawa
ISL Islington
BEN Benmore
INV Invercargill
Nominated for addition
MAN Manapouri
KIK
ISL
BEN
MAN
INV
Cobb
Stoke
Fighting Bay
Blenheim
Matiri
Kikawa
Branch River
Argyle
Robertson Street
Murchison
Rochfort
Inangahua
Reefton
Dobson
Greymouth
Arnold
Kumara
Hokitika
Culverden
Otira
Arthur's Pass
Waipara
Amethyst
Castle Hill
Ashley
Wahapo
Coleridge
Southbrook
Kaiapoi
Kimberley
Islington
Bromley
Hororata
Highbank
Norwood
Lauriston
Ashburton
Tekapo A
Tekapo B
Temuka
Ohau A
Twizel
Albury
Timaru
Ohau B
Ohau C
Benmore
Aviemore
Waitaki
Studholme
Black Point
Bells Pond
Livingstone
Frankton
Cromwell
Naseby
Oamaru
Clyde
Roxburgh
Manapouri
White Hill
Mahinerangi
Three Mile Hill
Halfway Bush
Waipori
South Dunedin
Berwick
Gore
Brydone
Balclutha
North Makarewa
Kaiwera Downs
Invercargill
Edendale
Tiwai
Key
Battery
Hydro
Solar
Thermal
Wind
Sub/Switching Station
Construction Voltage
50 kV, 66 kV
110 kV
220 kV
350 kV
Construction voltages shown. System as at June 2025

12 Appendix 2: Productive efficiency calculation in detail

This appendix provides detail behind the methodology used to calculate productive efficiency outlined in section 6 – Analysis of productive efficiency.

The calculation is a relatively simple six step process as outlined below.

Step		Formula
1	Determine decrease required in percentage share of retail opex This is the productive efficiency gain required to produce a net positive analysis on the investment	$PV = Capex - \frac{C_n}{(1+r)^n}$
2	Determine Incremental (PV) The cost to move from 1, to 2, to 3, to 4, to 5 additional hubs (measured in PV)	$IC = PV_b - PV_a$
3	Determine Constant Periodic Payment (PMT) The constant periodic payment required to pay off (or partially pay off) the investment, with a constant interest rate (8%), over a specified period (15 years)	$PMT = \frac{(PV(1+i)^n + FV)_i}{1-(1+i)^n}$
4	Determine Annual Cost per ICP ($) The cost per ICP at each of the prospective hubs of the annualised PMT	$C_{ICP} = \frac{PMT}{ICP_{Count}}$
5	Determine Annual share of retail opex The proportion of the annual electricity bill allocated to retail cost	$R_{Opex} = R_{Proportion} \times Av_{Cb}$
6	Determine decrease required in percentage share of retail opex This is the productive efficiency gain required to produce a net positive analysis of the investment	$A_{Op} = \frac{C_{ICP}}{R_{Opex}}$

Table 22 – Productive efficiency variables defined

Step	Variable	Name	Description
1	PV	Present Value	The equivalent value in the present of a sum of money transacted in the future. The present value sum would attain the future value if it was invested at compound interest for n periods. For upfront costs n = 0 so the PV of upfront costs is simply the upfront cost.
	Capex	Capital Expenditure	
	C_n	Cash flow at period n (n periods in the future)	Cash flow is the period n operational cost.
	r	Rate of Return	8% (0.08) which is the default discount rate recommended by the NZ Treasury (see section 3.4)
	n	Number of years	15 years (see section 3.4)
2	IC	Incremental PV	The difference in Present Value between moving (adding to the market) from none to one, one to two and two to three additional hubs
	PV_b	PV of the second increment	The PV of the second increment
	PV_a	PV of the first increment	The PV of the first increment (the PV_a of the first increment (adding one hub) is 0)
3	PMT	Payment (Constant Periodic Payment)	The constant periodic payment required to pay off (or partially pay off) the initial investment (given constant rate and specific period)
	FV	Future Value	An optional argument that specifies the future value of the loan/investment, at the end of n (nper) payments. If omitted, [fv] has the default value of 0.
	n	Number of Periods	Number of periods (15 years - see section 3.4)
	i	Interest (rate of return)	8% (0.08) which is the default discount rate recommended by the NZ Treasury (see section 3.4)
4	C_{ICP}	Cost per ICP	The constant payment per ICP required to pay back the investment
	ICP_{Count}	Number of ICPs	Number of ICPs at each nominated subset hub
	PMT	Payment (Constant Periodic Payment)	The constant periodic payment required to pay off (or partially pay off) the initial investment (given constant rate and specific period)
5	R_{Opex}	Retail Opex	The proportion ($) of the annual consumer bill made up by retail cost (all retail cost, including the opex component)
	$R_{Proportion}$	Retail Proportion	The retail share of the annual consumer bill (%)
	Av_{CB}	Average Price (Consumer Bill)	The average price of the annual consumer electricity bill
6	A_{OP}	Annual Opex (Reduction)	The reduction of the percentage share of retail opex required to be net positive on investment.
	C_{ICP}	Cost per ICP	The constant payment per ICP required to pay back the investment
	R_{Opex}	Retail Opex	The proportion ($) of the annual consumer bill made up by retail cost (all retail cost, including the opex component)

13 Appendix 3: Glossary

In addition to the terms listed below, we use the industry-standard three letter acronyms for hub names, with the existing and nominated subset hub names being covered in sections 0 and 2.5.

Term	Meaning
$/MW/h	Dollars per Megawatt per hour
Annualised incremental PV	Ther sum of capital and operational (opex) costs annualised over 15 years
Assignment Assignor Assignee	The Assignment of an FTR in accordance with clause 13.248 of the Code. Assignor and Assignee refer to the two parties to an Assignment.
Auction	A method for awarding FTRs for one or more FTR Periods based on FTR Participants' bids. One of (usually) two Auctions in an Auction Month, being either a Primary Auction or a Variation Auction.
Auction Month	The month in which an FTR Auction occurs.
Authority	The Electricity Authority.
CBA	Cost-benefit analysis
Clearing Manager	The party contracted by the Authority to provide clearing and settlement services to the wholesale electricity market.
Code	Electricity Industry Participation Code 2010.
EA	The Electricity Authority.
EMI	The Authority's Electricity Market Information platform *emi.ea.govt.nz*.
FTR	Financial Transmission Right.
FTR Duration	The length of the time period for which an FTR applies at settlement.
FTR Grid	The grid used by the FTR Manager to auction FTRs for an FTR Period.
FTR Holder	An FTR Participant that holds an FTR.

Term	Meaning
FTR Information System	The electronic systems provided or used by the FTR Manager for Auctions, Assignments, the FTR Register and registration of FTR Participants, and for any secondary market for FTRs.
FTR Manager	The market operation service provider who is, for the time being, appointed as the FTR manager for the purposes of the Code.

Term	Meaning
FTR Participant	A party who has been approved and registered by the FTR Manager to participate in an FTR Auction and to be Assigned FTRs.
FTR Period	The time period for which an FTR applies at settlement, the length of which is the FTR Duration.
FTR Type	An FTR can be either an Obligation FTR or an Option FTR.
FTR Volume	The amount of an FTR in MW (to 1 decimal place).
HEDGE FTR Market System®	The name of Resource Innovations (formerly Nexant Inc.) FTR product used by the FTR Manager to run the FTR Market.
HVAC	High voltage alternating current, being the North Island and South Island parts of the grid, less the HVDC.
HVDC	High voltage direct current, being the inter-island link from Benmore in the South Island to Haywards in the North Island.
Hub	A node or group of nodes (and in the case of a group of nodes, nodes in the group may be given different weightings) identified as either the Source Hub or the Sink Hub of an FTR. For FTR hub reviews we differentiate between: • Existing hubs, being those already in the FTR market as prescribed by the FTR Allocation Plan • Long-list hubs, being the FTR Manager's assessment of which nodes have sufficient levels of interconnection and capacity to act as effective FTR hubs • Nominated hubs, being Participant nominations • Short-list hubs, being a consolidated list of nominated hubs • Nominated subset of hubs, being those short-list hubs selected through the STV method • Recommended hubs, being those nominated hubs that, through this CBA process, the FTR Manager recommends that the Authority approve for inclusion in the FTR Allocation Plan.

Term	Meaning
ICP	Installation Control Point, being a point of connection where an electricity consumer connects to the distribution network
MW	Megawatts.
Opex	Operational cost.
Primary Auction	The first of two Auctions in a month.
Settlement Node	The node for each Hub at which Final Prices are used for the calculation of the FTR Hedge Value (Provisional)
Sink	The offtake Hub of an FTR.
Source	The injection Hub of an FTR.
STV	Single transferable vote
Trading Period	A period of 30 minutes ending on each hour or 30 minutes past each hour on any trading day.
Variation Auction	The second of two FTR Auctions in an Auction Month.
WIBR	Within-island basis risk, the title of an Authority work programme 2011 to 2013: see section 2.4.