Within-island basis risk: proposed approach

Consultation Paper

Submissions close: 5:00pm 6 August 2013

25 June 2013

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Executive summary

The recent introduction of financial transmission rights (FTRs) between Otahuhu (OTA) and Benmore (BEN) will assist participants in the New Zealand wholesale electricity market to manage spot price risk between the two islands. However, participants will still be exposed to spot price risk *within* each island (WIBR, within-island basis risk).

WIBR is a commercially material risk. There are initiatives currently underway that may reduce WIBR, but they will not eliminate it entirely. WIBR may deter competition in wholesale and retail markets, resulting in inefficiency, to the long-term disbenefit of consumers.

The Authority's statutory objective requires it to promote more competitive and efficient outcomes provided doing so delivers long-term benefits to consumers. The Authority prefers market solutions where possible – however, some mechanisms for managing WIBR cannot be implemented by participants alone. The Authority therefore considers that there is a case for it to consider options to assist participants to manage WIBR.

The Authority has identified a shortlist of four options.

- *Two-node hybrid:* Implement a loss rental allocation (LRA) within each island
- *Three-node FTR:* Add a new FTR node at Haywards (HAY), in addition to the existing FTR nodes at OTA and BEN
- *Three-node hybrid:* A combination of the two options above – to implement LRAs within each island *and* add a new FTR node at HAY
- *Multi-point FTR:* Add multiple new FTR nodes and/or hubs (collectively "points") around the country.

The Authority has formed a preliminary view that the *multi-point FTR* is the preferred option at this stage. This option is likely to have a higher net benefit than the other options, because it would support retail competition more effectively and would come at relatively little incremental cost. In particular, the *multi-point FTR* would be:

- more effective than the *hybrid* options because FTRs are tradable and LRAs are not
- more effective than the *three-node FTR* because it would provide more comprehensive hedge cover.

The Authority seeks feedback on this preliminary view.

If, following consultation, the Authority makes a decision to proceed with the *multi-point FTR*, then the FTR manager can begin to develop the new FTR products, which could be implemented by mid-2014.

Proceeding with the *multi-point FTR* would not rule out implementing LRAs or zonal pricing at a later date.

The Authority also seeks feedback on its provisional views on how new FTRs should be designed, *if* the decision is to proceed with the *multi-point FTR.*

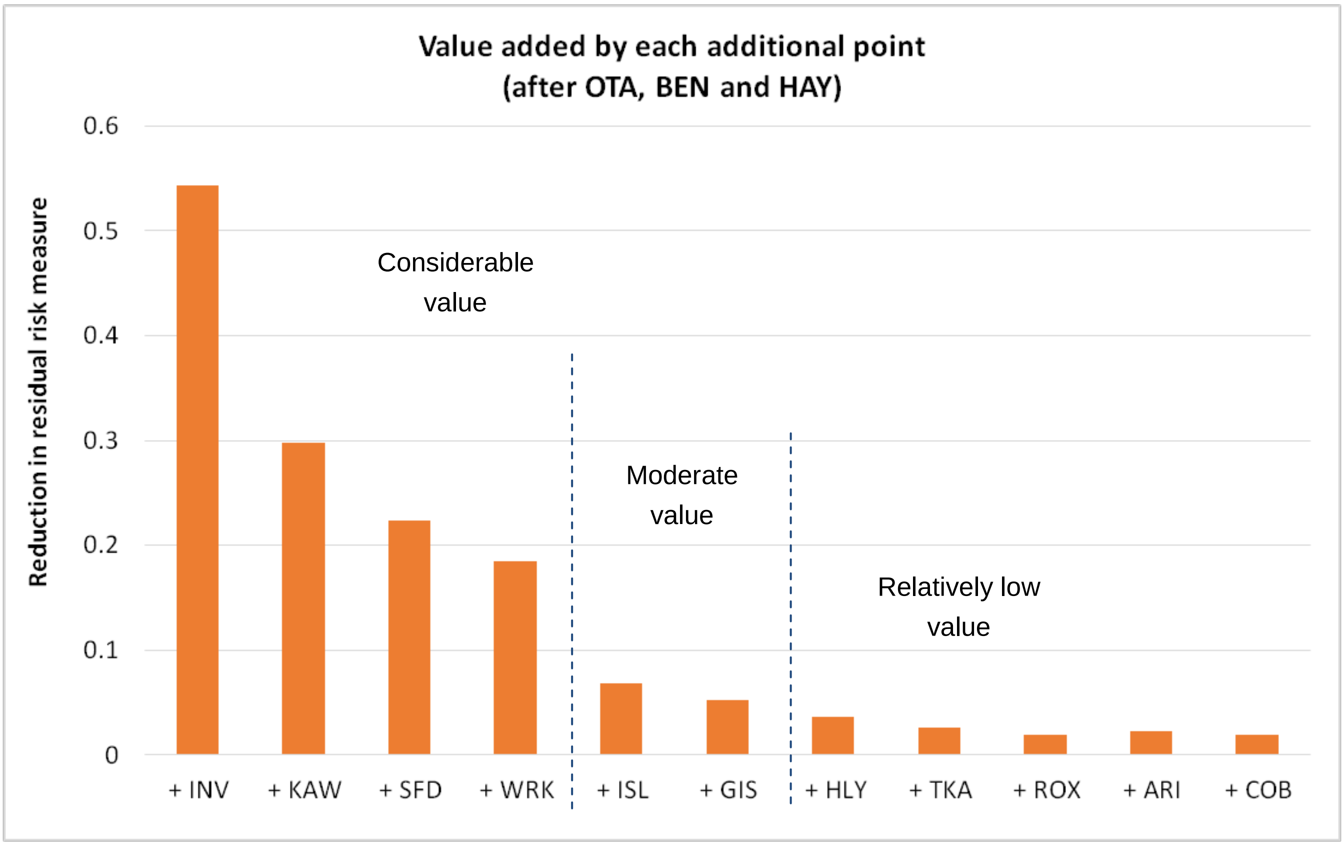
A key decision would be how many new FTR points should be added, and where. The Authority considers that at this stage the number of new points should be reasonably limited. This would keep the level of complexity manageable as well as address concerns about the potential for locally dominant suppliers to outbid other parties in the FTR market and about the potential for local suppliers to have uncapped incentives to exploit dominant positions in the spot market.

Statistical analysis[1] identifies that it may be most difficult for participants to reduce their exposure to WIBR in the lower North Island (LNI) using existing mechanisms. As a first step it might be preferable to add a new FTR node at Haywards (HAY) to provide participants with a tool to manage WIBR in the LNI.

Statistical analysis (shown overleaf) suggests that, after HAY, it might be preferable to add new FTR nodes at the following locations: Invercargill (INV), Kawerau (KAW), Wairakei (WRK), Stratford (SFD), and perhaps Islington (ISL) and Gisborne (GIS). More points could be added later if required.

However, commercial factors, such as the location of load and generation, are also relevant in the location of any new FTR nodes.

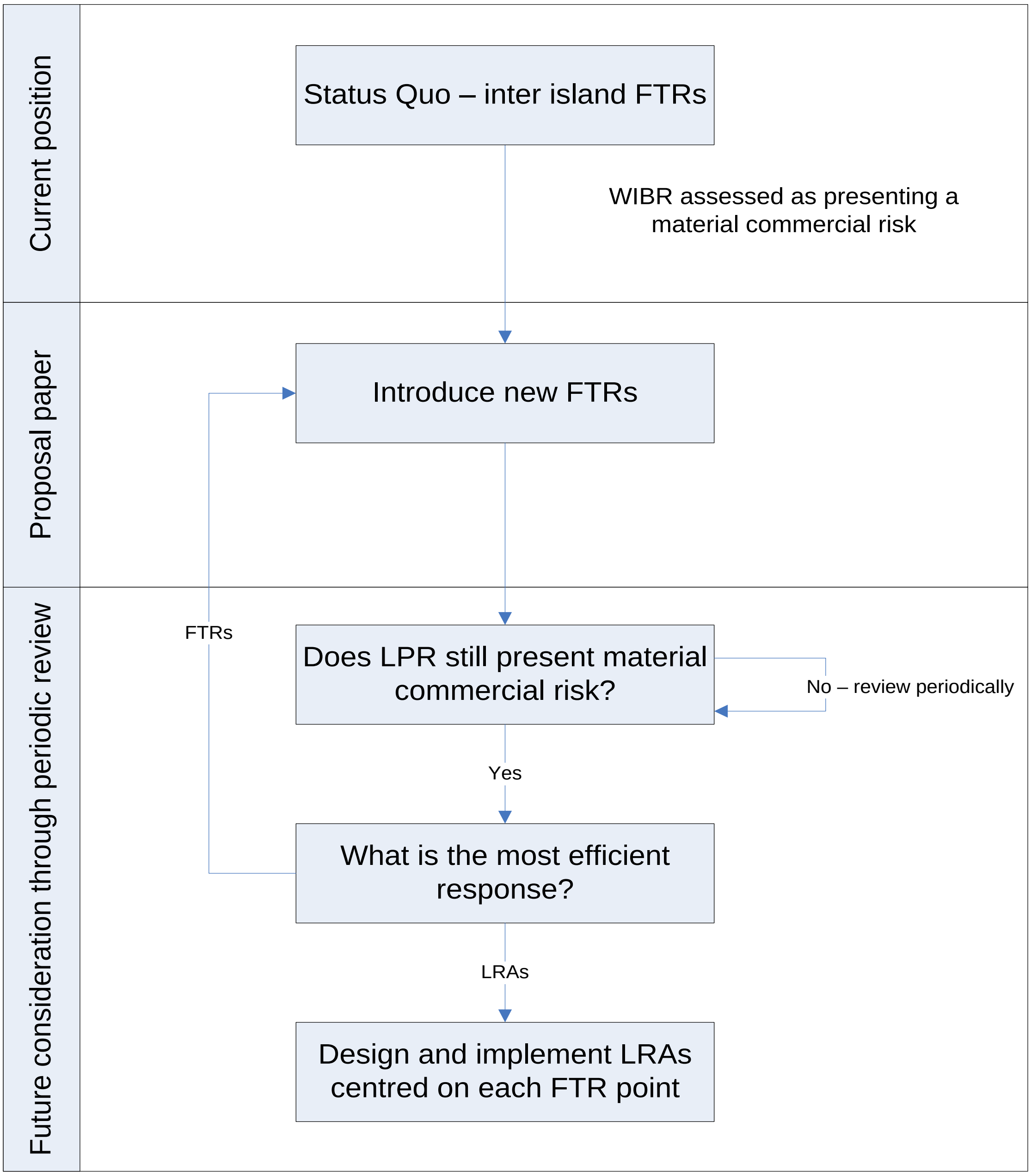
[1] See: *Within-island basis risk: quantifying the risk*, available from http://www.ea.govt.nz/our-work/advisory-working-groups/lprtg/14feb13/



The Authority also seeks feedback on its provisional preferences for:

- basing new FTRs on nodes rather than hubs (where a hub is a weighted combination of nodes)
- offering FTRs between every pair of FTR nodes, rather than using a radial system (where “spokes” extend from a key FTR node in each island)
- offering a full selection of option and obligation FTRs in both directions, rather than offering options only, or obligations only.

The Authority proposes a roadmap for addressing locational price risk in the longer term, conditional on a decision being made to proceed with the *multi-point FTR*. The roadmap is illustrated below:



Glossary of abbreviations and terms

Authority	Electricity Authority
CAPs	Code Amendment Principles
CFD	Contract for difference (a form of energy hedge)
Code	Electricity Industry Participation Code 2010
CVar	Conditional value at risk
FTE	Full-time equivalent
FTR	Financial transmission right
HMDSG	Hedge Market Development Steering Group
hub	An average of the prices at multiple nodes, typically weighted by load or generation quantities
hybrid	Combination of FTRs and LRAs
LNI	Lower North Island
LPR	Locational price risk – the commercial risk associated with *unpredictable* variations in price differences between nodes
LPRTG	Locational Price Risk Technical Group
LRA	Locational rental allocation
Multi-point FTR	Option involving several new FTR points around the country
NPV	Net Present Value
obligation	FTR paying the difference in price between two points (which may be positive or negative)
option	FTR paying the price difference in one direction only (which is always positive)
point	FTR node or hub
point-to-point	System of FTRs with FTRs between every pair of points
radial	System of FTRs extending from one or two central points to a larger number of points "in the provinces" (c.f. point-to-point)
TPM	Transmission Pricing Methodology
Three-node FTR	Option involving a new FTR node at Haywards
Three-node hybrid	Option involving a new FTR node at Haywards, and LRAs around each of Otahuhu, Haywards and Benmore
Two-node hybrid	Option involving an LRA in each island
WAG	Wholesale Advisory Group

WIBR	Within-island basis risk – the commercial risk associated with unpredictable variations in price differences between nodes *in the same island*
Zonal pricing	Reducing the number of nodes at which prices are calculated, with all load in a zone facing the same price (possibly adjusted for losses)

Contents

Tables

Figures

1. What you need to know to make a submission

1.1 What this consultation paper is about

1.1.1 The introduction of FTRs between OTA and BEN will assist participants in the New Zealand wholesale electricity market to manage spot price risk between the two islands. However, participants will still be exposed to spot price risk within each island (WIBR, within-island basis risk).

1.1.2 The Authority has investigated ways to help participants manage WIBR and is proposing that between five and seven new FTR points (in addition to OTA and BEN) should be offered.

1.1.3 The Authority invites you to make a submission on this proposal and the costs and benefits associated with it.

1.1.4 The Authority’s preferred approach does not require a Code amendment, rather it would be necessary only for the FTR manager to amend its FTR allocation plan. Therefore, this paper does not contain any amendments to the Code. If, following consultation, the Authority decides to proceed with another proposal, it will consult on any consequent Code amendments that are required.

1.2 How to make a submission

1.2.1 Your submission is likely to be made available to the general public on the Authority’s website. If necessary, please indicate any documents attached in support of your submission and any information that is provided to the Authority on a confidential basis. However, you should be aware that all information provided to the Authority is subject to the Official Information Act 1982.

1.2.2 The Authority’s preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix A. Submissions in electronic form should be emailed to submissions@ea.govt.nz with “Consultation Paper – Within-island basis risk: proposed approach” in the subject line.

1.2.3 Do not send hard copies of submissions to the Authority unless it is not possible to do so electronically. If you cannot or do not wish to send your submission electronically, you should post one hard copy of the submission to either of the addresses provided below or you can fax it to 04 460 8879. You can call 04 460 8860 if you have any questions.

Postal address

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

Physical address

Submissions
Electricity Authority
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

1.3 Deadline for receiving a submission

1.3.1 Submissions should be received by 5 pm on 6 August 2013. Please note that late submissions are unlikely to be considered.

1.3.2 The Authority will acknowledge receipt of all submissions electronically. Please contact the Submissions' Administrator if you do not receive electronic acknowledgement of your submission within two business days.

2. New mechanisms are needed to help participants to manage WIBR

2.1 Problem definition: Some wholesale market participants are exposed to WIBR

2.1.1 In the New Zealand electricity spot market, prices are calculated for around 260 nodes throughout the country in each trading period. Prices differ between these nodes, signalling locational differences in the value of supplying or consuming power. This is known as "nodal pricing".

2.1.2 For instance, if the price at node A is higher than the price at node B, then this signals that:

(a) an additional 1 MW of generation at A is of more value than an additional 1 MW of generation at B

(b) it is more expensive to serve an additional 1 MW of load at A than an additional 1 MW of load at B.

2.1.3 A disadvantage of nodal pricing is that it can give rise to locational price risk (LPR), which can inhibit retail competition (see Section 2.4).

2.1.4 In this paper, LPR is defined as the commercial risk associated with unpredictable variations in spot price differences between nodes. (A predictable price difference between nodes does not constitute a risk, even though it may be disadvantageous for some parties.)

2.1.5 Various kinds of participants are exposed to LPR in different ways. Some examples of downside risks[2] are that:

(a) an integrated generator-retailer faces the risk that the spot price may be higher at the nodes where they have retail customers than at the nodes where they generate power

(b) a pure retailer, or a major consumer, faces the risk that the price may be higher at the node(s) where they buy power than at the node(s) at which their hedge contracts are referenced

(c) a pure generator faces the risk that the price may be lower at the node(s) where they produce power than at the node(s) at which their hedge contracts are referenced

[2] downside risks are situations in which a participant can lose money as a result of LPR.

(d) a party with no physical position in the electricity market (such as a bank) may also be exposed to LPR, depending on the financial position they have taken.

2.1.6 LPR can be divided into inter-island basis risk and WIBR. WIBR is defined as the commercial risk associated with unpredictable variations in spot price differences between nodes in the same island.

2.1.7 WIBR can be divided into:

(a) *spikes* (the risk that there will be a much higher spot price at one node than another – typically associated with a transmission constraint between the two nodes)

(b) *tidal flows* (including all other LPR – largely driven by changes in losses caused by changes in the direction and magnitude of power flows, but also resulting from small to moderate price differences across intermittent transmission constraints).

2.1.8 Some historical examples of locational price differences are shown in Appendix B.

2.2 WIBR is a commercially material risk

2.2.1 In 2010 it was identified that WIBR is about one third of total LPR.[3]

2.2.2 The introduction of FTRs between OTA and BEN will assist participants to manage inter-island price risk, and will also help participants to manage WIBR within the North Island to some extent.[4] Nevertheless, some WIBR will remain.

2.2.3 The Authority presented a report titled *Within island basis risk; quantifying the risk*[5] to its Locational Price Risk Technical Group (LPRTG). This report uses statistical analysis to provide estimates of the level of WIBR to which participants will be exposed, concluding that:

(a) tidal flows cause WIBR throughout the country, but participants should largely be able to manage such risks using products denominated at OTA and BEN

3 http://www.ea.govt.nz/dmsdocument/8139

4 For instance, a hypothetical participant with load at HAY and generation at OTA could potentially reduce their WIBR by purchasing option FTRs from OTA to BEN.

5 http://www.ea.govt.nz/our-work/advisory-working-groups/lprtg/14feb13/

(b) spikes can cause much higher WIBR in some local areas – recently exacerbated by pivotal supplier behaviour[6]

(c) LPR in the LNI can be managed using a combination of products denominated at OTA and BEN, but this may be expensive and some risk may remain.

2.2.4 The LPRTG largely concurred with the conclusions of the report, but emphasised that "the future is different from the past". Backward-looking statistical analysis can identify locational price differences that have occurred in the past, but there is always the possibility that new risks will occur in the future. Therefore, there may be a material level of LPR in some areas not identified in the report.

2.3 Current initiatives may reduce WIBR but will not eliminate it

2.3.1 There are several initiatives currently underway which may affect the level of WIBR.

Transpower's transmission investment programme

2.3.2 WIBR arises from transmission losses and constraints. Transpower's investment programme will reduce losses and relieve constraints in some areas.[7]

2.3.3 Nevertheless, Transpower's investment programme will not eliminate WIBR, because:

(a) new transmission constraints will arise over time

(b) it is not always economic to relieve constraints

(c) when Transpower does act to relieve a constraint, the process of upgrading the network can actually cause constraints in the short term (as a result of planned outages for commissioning new lines).

Pivotal supplier situations

2.3.4 Pivotal supplier situations are a key source of WIBR.[8]

2.3.5 The Wholesale Advisory Group (WAG) is pursuing a project to address pricing in pivotal supplier situations.[9] This initiative has the potential to reduce WIBR in some areas.

[6] http://www.ea.govt.nz/our-work/consultations/advisory-group/pivotal-supplier-situations/

[7] https://www.transpower.co.nz/projects

[8] http://www.ea.govt.nz/dmsdocument/13478

Constraint softening

2.3.6 High spring washer (HSW) price situations are a key source of WIBR.[10]

2.3.7 The Authority is pursuing a project to consider constraint softening as a way of resolving HSW situations. This initiative has the potential to affect the level of WIBR in some areas.

2.3.8 The Authority expects to release a consultation paper on constraint softening concepts during the third quarter of 2013.

The Authority's review of the transmission pricing methodology (TPM)

2.3.9 The Authority's review of transmission pricing could impact the availability of loss and constraint excess (LCE) to fund solutions to WIBR. The current transmission pricing proposal seeks to allocate the LCE to individual assets from which the LCE originates. This would alter the extent to which the existing allocation of LCE to transmission customers mitigates WIBR. Neither the existing allocation of LCE nor the proposed TPM LCE proposal are designed to reduce WIBR, rather they have the primary purpose of offsetting the impact of transmission charges.

Improved modelling of losses

2.3.10 The Authority is undertaking a project to review the number of loss tranches used in SPD. Increasing the number of tranches used in SPD will improve price accuracy. However, it is unclear at this stage what effect, if any, this will have on WIBR.

A material level of WIBR will remain

2.3.11 The Authority's view is that, even once all of the above initiatives have been implemented, some participants will still be exposed to a material level of WIBR.

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[9] http://www.ea.govt.nz/our-work/advisory-working-groups/wag/

[10] A high spring washer price situation is the most common mechanism by which a price higher than the offer price of the most expensive dispatched generation on the national transmission grid can occur. High spring washer prices occur at nodes where the system operator's Scheduling, Pricing and Dispatch model (SPD) has to replace multiple units of low-priced generation with high-priced generation, so that an additional unit of generation can be delivered to those nodes whilst meeting the grid constraints built into SPD.

2.4 WIBR may deter competition, to the long-term disbenefit of consumers

2.4.1 There are various possible strategies that participants can use to reduce their exposure to WIBR, or to mitigate their WIBR. Some of these are:

(a) purchasing a combination of exchange-traded energy hedges denominated at multiple nodes (OTA and BEN) – in preference to purchasing all their energy hedges at a single node

(b) entering into bilateral arrangements – e.g. using contracts for difference (CFDs) at or near their local node(s)

(c) confining investment in generation to areas where they already have customers

(d) acquiring customers in areas where they already have generation, and offloading customers in areas where they do not

(e) operating embedded generation at nodes where the price is high

(f) reducing demand at nodes where the price is high.

2.4.2 Some of these responses may be efficient. For instance, it is efficient for participants to reduce demand at a node when the cost of doing so is less than the nodal price. However, other responses may act to reduce competition and hence introduce inefficiency.

2.4.3 In particular, if generator-retailers do not seek customers in areas where they do not already have generation, then there will be limited retail competition in such areas. This will tend to:

(a) reduce productive efficiency by easing the pressure on retailers to innovate, improve their processes and reduce the costs they face

(b) reduce allocative efficiency by allowing retail margins to increase, resulting in deadweight loss.

2.4.4 Such efficiency losses are to the long-term disbenefit of consumers.

2.5 There is a case for regulatory intervention

2.5.1 The Authority’s statutory objective requires it to promote more competitive and efficient outcomes provided doing so delivers long-term benefits to consumers.

2.5.2 Efficiencies could be achieved either by:

(a) reducing the extent of WIBR, or

(b) providing new mechanisms to assist participants to manage WIBR.

2.5.3 The Authority prefers market solutions where possible. However, some mechanisms for managing WIBR cannot be implemented by participants alone, because they are dependent on amendments being made to the Code.

Although introducing more FTR nodes may not require a Code amendment, the Authority considers that there is a case for it to consider all options to assist participants to manage WIBR.

2.5.4 Short-listed options for managing WIBR are set out in Section 3.

Q1. Do you agree that the Authority has characterised the problem of WIBR correctly? If not, how could the problem be better described?

3. The Authority has identified a short-list of four options to manage WIBR

3.1 The Authority has drawn on previous work

3.1.1 There is a considerable body of work on possible mechanisms to manage LPR in the New Zealand context.

3.1.2 FTRs were proposed overseas as early as the 1980s.Transpower proposed the introduction of FTRs to New Zealand, to assist with LPR management, in the late 1990s. The Electricity Authority, and its predecessor, the Electricity Commission, have been running an LPR workstream since 2008, with the assistance of the Hedge Market Development Steering Group (HMDSG) and, more recently, the LPRTG.

3.1.3 In the process of identifying high-level options for managing WIBR, the Authority has drawn on previous work carried out in the course of the LPR workstream. To date, the three types of mechanisms that have received the most attention are:

(a) FTRs

(b) locational rental allocations (LRAs)

(c) zonal pricing.

3.1.4 An FTR is a purchasable right to receive the price difference[11] between two nodes or hubs, for a defined duration, multiplied by a defined quantity. Some participants can reduce their exposure to LPR by acquiring an appropriate combination of FTRs. FTRs are widely used internationally to manage LPR in electricity markets.

3.1.5 An LRA is an allocation of LCE[12] among spot market purchasers, possibly combined with a reallocation of funds between purchasers, so as to reduce locational differences in the effective nodal price. A suitably designed LRA could reduce some participants' exposure to LPR. LRAs are not used outside New Zealand.

3.1.6 Zonal pricing is a reduction in the number of nodes at which there is trading in the wholesale market (with all load in a zone facing the same price – possibly adjusted for losses). A suitably designed zonal pricing

[11] Or the uni-directional price difference (i.e. an option), or as sometimes formulated, the rentals. The rental generated by a transmission circuit in a specific time period is the product of the (unsigned) flow over the circuit by the price differential across the circuit.

[12] The LCE is the difference between total receipts and total payments in the spot market, and (in the absence of default) is the sum of the rentals generated by all transmission circuits.

regime could reduce some participants' exposure to LPR. All wholesale markets are zonal to some extent, and some are more so than the New Zealand market.

3.1.7 Any new mechanisms to manage WIBR must be compatible with FTRs between OTA and BEN, which were introduced on 12 June 2013 to assist participants to manage inter-island price risk. These inter-island FTRs are described in Appendix C.

3.2 Four high-level options have been identified

3.2.1 The Authority has identified a shortlist of four high-level options for assisting participants to manage WIBR.

3.2.2 Some of the shortlisted options involve creating additional FTR products, using new nodes or hubs[13] (collectively referred to as "points" in this paper). This would make it more viable for participants to purchase a combination of FTRs that reduces their exposure to LPR.

3.2.3 Some of the shortlisted options incorporate LRAs. This would help to insulate some wholesale purchasers from the effects of WIBR.

3.2.4 The four options are listed below (and summarised in Table 1).

(a) *Two-node hybrid:* Retain FTRs between OTA and BEN and implement within-island LRAs. It may be helpful to think of this option as creating "two LRAs" – in that the LRA would hedge to a different price in each island.

(b) *Three-node FTR:* Retain FTRs between OTA and BEN and add a new FTR node at Haywards (HAY).

(c) *Three-node hybrid:* Retain FTRs between OTA and BEN, add a new FTR node at HAY, *and* implement within-island LRAs. It may be helpful to think of this option as creating "three LRAs" – in that the LRA would hedge to different prices at BEN, HAY and OTA, with a continuum of prices between HAY and OTA.

(d) *Multi-point FTR:* Retain FTRs between OTA and BEN and add multiple new FTR points around the country.

[13] In this paper, a *hub* price is defined as an average of the prices at multiple nodes, typically weighted by load or generation quantities. Confusingly, in some other contexts the term *hub* has a different meaning – for instance, a central node in a "hub-and-spoke" FTR design.

Table 1 Four high-level options

	Two-node hybrid	Three-node FTR	Three-node hybrid	Multi-point FTR
New FTR nodes and/or hubs		One	One	Several
LRAs	Yes		Yes	

3.2.5 The status quo is not one of the high-level options – rather, it is a counterfactual against which these options are compared.

3.2.6 The four options are described individually in Sections 3.4 through 3.7. As will be seen, there are several possible variations of each of the options. The four options are compared against each other in Section 4.

Q2. Do you agree that these four options are an appropriate shortlist? If not, are there other options that should be considered?

3.3 Other options were considered but not pursed

3.3.1 Options that the Authority has considered, but decided not to develop further at this stage, are shown in Table 2.

Table 2 Options not included at this stage

Option	**Authority's view**	**Rationale**
Zonal pricing	Not one of the shortlisted options at this point	Reducing the number of nodes at which wholesale prices are calculated would distort spot market outcomes and is not within the scope of this project. However, none of the options under consideration would rule out implementing zonal pricing at some future time (if it was efficient to do so).
Full FTR coverage, with FTRs offered between *all*	Not one of the shortlisted options at this point, but is still an option in the longer term	In the short to medium term this option would seem prohibitively complex for most participants, and for the Authority's market monitoring function. It might also raise implementation difficulties for the Authority's

pricing nodes		service providers.[14] Further, it might give rise to concerns with regard to the incentive on locally dominant suppliers to outbid other parties and impact on spot market behaviour (see Appendix D). However, it is possible that full FTR coverage may be efficient in the long-term.
Adding multiple new FTR points *and* LRAs	Not one of the shortlisted options at this point, but would still be an option not ruled out by any of the options considered in the longer term	In the short to medium term this option would seem prohibitively complex for some participants. It would also mean that the introduction of new FTR points would be delayed until LRAs could be implemented. However, if the *multi-point* FTR option was adopted, then LRAs could still be implemented at some future time (if it was efficient to do so).

3.3.2 Section 6.2 sets out how these options might be considered in future.

Q3. Do you agree that the four options in Table 2 need not be considered at this stage? If not, which of them should be considered and why and what other options should be considered and why?

3.4 Option 1 is a *two-node hybrid*

3.4.1 Under this option, FTRs between OTA and BEN would be retained and within-island LRAs would be implemented.

3.4.2 It may be helpful to think of this option as creating “two LRAs” – in that the LRA would hedge to a different price in each island.

3.4.3 Under this option, there would be no additional FTR points in the short term. Further, adding more FTR points at a later date could cause problems, as this would mean removing some of the funding that underpinned the LRAs.

3.4.4 The Authority has not reached any firm decisions on how LRAs would be designed or implemented if this high-level option was to be adopted.

14 Even if these difficulties could be resolved by a specific service provider, they might make it prohibitively difficult for other parties to compete for the same service provider role.

However, Table 3 lists some key design decisions and indicates the Authority's tentative preference in each case.

3.4.5 The primary effect of the LRAs described in Table 3 would be that spot purchasers would largely be insulated from the effect of within-island price differences – providing they were drawing power at their average historical level. They would still face an efficient spot price signal for any deviations from their average historical level. This signal would continue to incentivise them to reduce load at times of scarcity, unlike zonal pricing.

3.4.6 It will be noted that the Authority's tentative preferences in Table 3 generally favour the simplest choice (except where this would compromise efficiency). This is because the two-node hybrid is intended to be a simple option that is easy for participants to understand and participate in.

3.4.7 An LRA design consistent with the preferences in Table 3 is set out in Appendix E.

Q4. Do you agree that the two-node hybrid option has been characterised correctly? If not, how could it be better described?

Table 3 Key design decisions for the *two-node hybrid* option

Design issue	Authority's preliminary preference	Rationale
Generator participation?	Only spot purchasers would participate in the LRAs.	Including generators in such an LRA would remove locational price signals for investment in, and operation of, generation. This mechanism is aimed at improving retail competition.
One-sided or two-sided?	Two-sided – purchasers would pay into the LRA at some times and receive payments at other times.	Opting for a one-sided LRA would limit the hedge value.

Design issue	Authority's preliminary preference	Rationale
Price hedged against	Two prices – OTA and BEN. Within each island, participants would be hedged against the price at the island reference node (adjusted for losses and a factor to achieve revenue adequacy, see Appendix E).	This approach would retain LPR between OTA and BEN, which participants can manage using inter-island FTRs and trading of futures contracts etc.
Quantity used to determine payout	Payouts to a purchaser at a node would be based on the purchaser's average quantity over some earlier time period, rather than their actual quantity in the payout period. Quantity would be calculated gross of embedded generation to the extent possible. Some arrangements would need to be made for estimating the quantity assigned to a new participant.	If the payout was based on actual quantity in the payout period, then the LRA would remove locational signals for demand-side response, which would be inefficient. Using the average quantity over a previous period would retain efficient price signals (as set out in Appendix F). Treatment of embedded generation should be consistent with grid-connected generation.
Treatment of losses	After applying the LRA, the effective price at a node would reflect the average level of marginal losses affecting that node.	As set out in Appendix E, this approach is consistent with the marginal pricing nature of the NZ market and reduces distortion to long-term price signals.
Participation factors to isolate price differences caused by constraints	Participation factors would not be used.	The use of participation factors would add complexity, and would expose participants to local variations in losses.

Design issue	Authority's preliminary preference	Rationale
Locationally varying premium for participants who choose to opt in	Participants would not be charged a premium (locationally varying or otherwise). Participants might be given the option to opt out (without receiving any rebate).	The option of charging a premium would add undue complexity. Some participants might find that LRAs (as described in Appendix E) would not improve, and might even worsen, their exposure to LPR. Allowing these participants to opt out might be beneficial, and would add little complexity to the scheme. However care would need to be taken to avoid "flip-flopping" (i.e. rapid entry and exit from the LRA).
Revenue shortfall and surplus	Any surplus or deficit in a given month should result in scaling (rather than being carried over to the next month).	Consistent with the FTR design
Tradable LRAs	The LRAs would not be tradable.	LRAs could be designed to be tradable or auctionable, but this would add undue complexity. If it is essential for participants to be able to tailor their own position, then a tradable option (involving FTRs) is preferable.
Funding	The LRA would be funded by all interconnection rentals except those used to fund inter-island FTRs.[15]	All available LCE should be used in order to maximise hedge cover. Connection rentals, and rentals used to fund the inter-island FTR, are not available.

[15] subject to requirements of other Authority initiatives e.g. transmission pricing

Design issue	Authority's preliminary preference	Rationale
Implementation date	Fully developing and implementing LRAs would take some time. Implementation should be transitioned.	Providing a transition period would give participants time to unwind their existing hedge arrangements (if this proved necessary).

3.5 Option 2 is a *three-node FTR*

3.5.1 Under this option, FTRs between OTA and BEN would be retained and a new FTR node would be added at HAY, in order to provide participants with a tool to manage WIBR in the LNI. Statistical analysis identifies that it may be difficult for participants to reduce their exposure to WIBR in the LNI using existing mechanisms. WIBR in South Island appears to be easier to manage.[16]

3.5.2 It would be possible at a later stage to add more FTR points and/or to implement LRAs or zonal pricing.

3.5.3 The Authority has not reached any firm decisions on design issues. However, Table 4 lists some key design decisions and indicates the Authority's tentative preference in each case.

3.5.4 Table 4 explains each of the key design issues. It may also be useful to refer to Appendix C, which describes the design of inter-island FTRs.

3.5.5 The Authority's tentative preferences in Table 4 favour consistency and compatibility with inter-island FTRs wherever possible.

Q5. Do you agree that the three-node FTR option has been characterised correctly? If not, how could it be better described?

[16] *Within-island basis risk: quantifying the risk*, available from http://www.ea.govt.nz/our-work/advisory-working-groups/lprtg/14feb13/

Table 4 Key design decisions for the *three-node FTR* option

Design issue	**Authority's tentative preference**	**Rationale**
Location and type of new point	Node at HAY.	Goal is to cover WIBR in the LNI. Locating the new point at HAY would support active trading of energy contracts at HAY.
Radial or point-to-point	Point-to-point – with products covering OTA-HAY, HAY-BEN *and* OTA-BEN.	OTA-BEN products could in theory be removed, but retaining them would provide participants with flexibility.
Products offered	Both options and obligations. Term and unit should be the same as for OTA-BEN.	Consistency with inter-island FTRs.
Funding	Status quo.	Schedule 14.6 of the Code already provides for additional nodes.
Implementation date	Mid-2014.	It would be preferable to put new FTRs in place as soon as possible, in order to provide participants with tools to manage their commercial risk. The FTR manager has indicated that new FTRs could be implemented by mid-2014.

3.6 Option 3 is a *three-node hybrid*

3.6.1 This option is basically a combination of the two previous ones. The FTRs between OTA and BEN would be retained and:

(a) a new FTR node would be added at HAY

(b) within-island LRAs would be implemented.

3.6.2 It may be helpful to think of this option as creating “three LRAs” – in that the LRA would hedge to three prices, at BEN, HAY and OTA, with gradation between HAY and OTA.

3.6.3 If this option was adopted, it might be difficult to create additional FTRs at a later date, as this would mean removing some of the funding that underpinned the three LRAs.

3.6.4 Table 5 lists some key design decisions and indicates the Authority’s tentative preference in each case.

3.6.5 An LRA design consistent with the preferences in Table 3 is set out in (Appendix E).

Q6. Do you agree that the three-node hybrid option has been characterised correctly? If not, how could it be better described?

Table 5 Key design decisions for the three-node hybrid option

Element	Design issue	Authority’s tentative preference	Rationale
FTRs	All design issues	As per Option 2: three node FTR	See Table 4.

Element	Design issue	Authority's tentative preference	Rationale
LRAs	Prices hedged against	Three prices – OTA, HAY and BEN. Within the SI, a participant would be hedged against the price at BEN (adjusted for losses and a factor to achieve revenue adequacy). Within the NI, a participant would be hedged against a weighted average of the prices at OTA and HAY (adjusted as above). The weights might depend on latitude (e.g. the weight assigned to OTA would be higher for nodes towards the north end of the island). See Appendix E for more detail.	This approach would not help to manage LPR between OTA, HAY and BEN, however such risk could be managed using FTRs.
	All other issues	As per Option 1: two node hybrid	See Table 3.

3.7 Option 4 is an *multi-point FTR*

3.7.1 Under this option, the FTRs between OTA and BEN would be retained and multiple new FTR nodes or hubs (collectively "points") would be added throughout the country.

3.7.2 It would be possible at a later stage to add more FTR points or to implement LRAs or zonal pricing, or both.

3.7.3 Table 6 lists some key design decisions and indicates the Authority's tentative preference in each case. It may also be useful to refer to Appendix C, which describes the design of inter-island FTRs.

3.7.4 The Authority's preliminary preferences in Table 6 favour consistency and compatibility with inter-island FTRs wherever possible.

Q7. Do you agree that the multi-node FTR option has been characterised correctly? If not, how could it be better described?

Table 6 Key design decisions for the *multi-point FTR* option

Design issue	Authority's preliminary preference	Rationale
Locations of new nodes and/or hubs	Strawman proposal: Haywards (HAY), Invercargill (INV), Kawerau (KAW), Stratford (SFD), Wairakei (WRK), and *perhaps* Islington (ISL) and Gisborne (GIS). More nodes or hubs could be added later if required.	Statistical analysis[17] shows that these nodes would be sufficient to cover the great majority of remaining LPR. Adding more nodes could increase concerns about complexity and/or the incentives on locally dominant suppliers (Section 5.2). However, this does not reflect other commercial considerations.
Nodes or hubs?	Nodes where appropriate.	Nodes are simpler, but the Authority understands there are technical issues here and would be guided by the FTR manager (Section 5.3).
Radial or point-to-point?	Point-to-point.	Allowing FTRs between any two points would make it easier for traders to obtain the portfolio they require (Section 5.4).
Options, obligations or both?	Full selection of option and obligation FTRs in both directions.	Providing all options and obligations would give traders more flexibility (Section 5.5).
Funding	Status quo.	Schedule 14.6 of the Code already provides for additional nodes.
Products offered	Term and unit should be the same as for OTA-BEN.	Consistency with inter-island FTRs.

17 Within-island basis risk: quantifying the risk, available from http://www.ea.govt.nz/our-work/advisory-working-groups/lprtg/14feb13/

Design issue	Authority’s preliminary preference	Rationale
Implementation date	Mid-2014.	It would be preferable to put new FTRs in place as soon as possible, in order to provide participants with tools to manage their commercial risk. The FTR manager has indicated that new FTRs could be implemented by mid-2014.

4. The Authority's preference at this stage is Option 4: the *multi-point FTR*

4.1 The Authority sets out its framework for deciding on a preferred option

4.1.1 The previous section identifies four high-level options. In Sections 4.2-4.4, the Authority has applied the following filtering criteria:

(a) options must be *feasible*

(b) options must not introduce a material *distortion* to efficient price signals in the wholesale market

(c) options must support the Authority's statutory objective, by enhancing *competition* (leading to improved *efficiency)*.

4.1.2 The Authority considers that all four options meet the first two criteria.

4.1.3 Section 4.4 identifies that the option that ranks highest against the third criterion (supporting competition) is the multi-point FTR.

4.1.4 Section 4.6 therefore provides cost-benefit analysis, comparing two options against each other and the status quo:

(a) the *multi-point FTR (*the pure FTR option that ranks highest against the competition criterion)

(b) the *two-node hybrid* (used as a counterfactual because it is the hybrid option that ranks highest against the competition criterion).

4.1.5 The multi-point FTR has the higher estimated net benefit and is therefore the Authority's preferred option at this stage.

4.1.6 The Authority seeks feedback on this conclusion and the supporting analysis.

4.2 All four options are feasible

4.2.1 The Authority considers that all four high-level options are feasible – that is to say:

(a) they would be legal

(b) they are mathematically valid

(c) the FTR manager would be able to implement the additional FTR products described, using existing software

(d) it would be possible for a party to implement the LRAs described.

Q8.	**Do you agree that all four high-level options are feasible? If not, why not?**

4.3 All four options would avoid distortion to price signals

4.3.1 The Authority would not favour any option for managing WIBR that was found to introduce a material distortion to efficient price signals in the wholesale market.

4.3.2 The Authority considers that none of the high-level options assessed would substantially distort efficient incentives for:

(a) generation siting decisions

(b) operation of generation

(c) demand-side siting decisions

(d) demand-side consumption decisions.

4.3.3 Some earlier LRA designs would have distorted demand-side consumption decisions. As set out in Appendix F, the Authority:

(a) considers that the LRA designs currently under consideration would largely avoid this problem, but

(b) acknowledges that this point is not universally agreed.

4.3.4 LRAs can, in theory, distort efficient incentives for load siting decisions. However, this might not be a material problem, as:

(a) load siting is generally based on considerations other than locational differences in the price of electricity

(b) the LRA designs discussed in this paper largely avoid such distortions by hedging against a price adjusted for averaged marginal losses.

4.3.5 Both FTRs and LRAs could affect the incentive on a locally pivotal supplier to influence the spot price. LRAs would generally increase the incentive in the short term, while FTRs could either increase or decrease it, depending on the supplier's FTR holdings. However, the conduct of a pivotal supplier would be the object of scrutiny by other participants, and by the Authority in its market monitoring capacity. Any FTR holdings or LRAs that affected the pivotal supplier's incentives would be a matter of public record. It is therefore the Authority's view that the effect on incentives faced by locally pivotal suppliers need not be a decisive consideration when considering whether to introduce new FTRs or LRAs. (This issue is discussed in more detail in Appendix D.)

Q9.	**Do you agree that all four options would avoid distortion to price signals? If not, why not?**

4.4 The Authority proposes criteria to determine which option would most support the statutory objective

4.4.1 The introduction of additional mechanisms to address WIBR would be intended to support the competition limb of the Authority's statutory objective – which, in turn, would support efficiency, to the long-term benefit of consumers. The reliability limb would not be affected.

4.4.2 This section proposes criteria for determining the high-level option that would most support competition. The proposed criteria are listed in Table 7.

4.4.3 The Authority considers that these criteria are roughly equal in priority.

Q10.	**Do you agree that the criteria in Table 7 are reasonable and roughly equal in priority? If not, why not? Should other criteria relating to competition, reliability or efficiency be considered?**

Table 7 Criteria for evaluating the options

No.	Criterion
1	**Simple and understandable for traders** Even if the inner workings of an option are complex, it is important that traders can easily understand how to use it and what the implications are. Complex options might actually have the perverse effect of reducing competition if only a few well-resourced participants could understand them well enough to use them effectively.
2	**Assists participants to manage WIBR in the LNI** Statistical analysis identifies that there may be a material level of WIBR in the LNI and participants may find it difficult to manage the risk using existing instruments.[18]
3	**Assists participants to manage WIBR associated with local spikes in various parts of the grid** Statistical analysis identifies the potential for spikes to cause high levels of WIBR in various local areas. [19]
4	**Tradable** If an instrument is tradable, then each participant can seek to take a position that meets their own needs.
5	**Flexible** It is likely that new sources of WIBR will arise over time. It would be preferable if the regime for managing WIBR either assisted participants to manage a wide spectrum of WIBR, or could be modified to address new risks as they became apparent.
6	**New-entrant friendly** A key feature supporting competition is the threat of new entry. It would be preferable if an option to address WIBR could specifically cater to the needs of new entrants. At the least, it should be designed in a way that does not discourage them from entering the market.
7	**Can be implemented soon** All else being equal, it would be preferable for new mechanisms to be in place sooner rather than later.

[18] Within-island basis risk: quantifying the risk, available from http://www.ea.govt.nz/our-work/advisory-working-groups/lprtg/14feb13/

[19] Ibid

4.5 The *multi-point FTR* rates highest against these criteria.

4.5.1 Assessment of the four high level options against the statutory objective criteria was conducted with the help of LPRTG. A summary of that assessment is produced in Table 8. More detailed assessments for each individual criterion can be found in Appendix F.

Table 8: Summary of evaluation of options against statutory objective criteria

	Simple and understandable to traders	Assists participants to manage WIBR in the LNI	Assists participants to manage local spikes in various parts of the grid	Tradable	Flexible	New-entrant friendly	Can be in place soon
Status quo	✓✓✓	X	X	✓	✓✓	X	✓✓✓
Two-node hybrid	✓✓	Load: ✓✓ Generation: X	✓✓✓	✓	✓	✓✓	✓
Three-node FTR	✓✓	✓	✓	✓✓	✓✓	✓✓	✓✓
Three-node hybrid	✓	Load: ✓✓ Generation: ✓	✓✓✓	✓	✓	✓✓	LRAs: ✓ FTRs: ✓✓
Multi-point FTR	✓✓ (for moderate numbers of new FTR points)	✓✓	✓✓	✓✓	✓✓	✓✓	✓✓

4.5.2 Based on this evaluation, the Authority has formed the preliminary view that the multi-point FTR would be most effective in promoting the competition limb of its statutory objective.

4.5.3 The multi-point FTR appears superior to the hybrid options, because:

(a) FTRs are tradable and would allow participants to tailor their hedge position to their individual needs

(b) proceeding with FTRs at this stage would retain more flexibility (e.g. to add more FTR nodes, or implement LRAs or zonal pricing)

(c) new FTRs could be in place by mid-2014, while LRAs would take longer to develop and implement.

4.5.4 The multi-point FTR also appears superior to the three-node FTR, in that it would provide more comprehensive hedge cover, while still being reasonably simple and understandable.

4.5.5 Of the two LRA-based options, the two-node hybrid appears superior to the three-node hybrid (which is more complex and harder to understand).

Q11. Do you agree that the multi-point FTR would promote the Authority's statutory objective most effectively? If not, why not, and which option do you think would most support the statutory objective?

4.6 Cost-benefit analysis supports the *multi-point FTR*

4.6.1 This section compares the costs and benefits of the *multi-point FTR* (which is considered to be the superior FTR option) and the two-node hybrid (which is the superior hybrid option), both relative to the status quo.

4.6.2 All costs and benefits are in real terms. All PV calculations cover a ten-year period[20] and use an 8% real discount rate. The long-term price elasticity of electricity demand is assumed to be -0.26. Analyst resource is costed at $120,000 per year.

4.6.3 Greater use of hedging does not constitute a benefit in and of itself. However, increased opportunities for locational hedging would enable more competition for retail customers in regions subject to WIBR. This, in turn, would give rise to the two sources of benefit considered in the CBA:

(a) an increase in *productive efficiency* from supporting retail competition, which will increase the pressure on retailers to innovate, improve their processes and reduce the costs they face

(b) an increase in *allocative efficiency* from supporting retail competition, which will tend to reduce retail margins, resulting in consumers facing a more cost-reflective price, and reducing deadweight loss.

4.6.4 The increase in productive efficiency is estimated to be the more significant of the two benefits.[21]

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20 It would seem inappropriate to use a longer period, given that a decision to proceed with a particular option at this point does not preclude further development at a later stage.

21 Allocative efficiency gains are likely to be modest. Consider the possibility of a $2/MWh reduction in the variable component of delivered prices, for 20% of load throughout New Zealand. Assume further that the average variable component of delivered prices is $150/MWh. With a price elasticity of -0.26, this would result in an efficient increase in electricity consumption of 28 GWh per year. The resulting reduction in deadweight loss is estimated at just $28K per year ($0.5\Delta P\Delta Q$) – well under $1M NPV.

4.6.5 The costs set against these benefits are:

(a) development costs

(b) implementation costs incurred by service providers

(c) on-going analytical resource costs incurred by participants (in trading) and the Authority (in FTR market monitoring).

4.6.6 These costs are incremental on the costs that will be incurred as a result of implementing inter-island FTRs (and are therefore relatively small).

4.6.7 Estimated costs are set out in Table 10, and total:

(a) \$3.2M PV for the multi-point FTR

(b) \$2.2M PV for the two-node hybrid.

4.6.8 The benefit that would be achieved is not certain. Table 9 shows how the net economic benefit would depend on the gross productive and allocative efficiency gains.

Table 9 Economic benefit of the multi-point FTR and two-node hybrid (\$M NPV)

	Efficiency gains are 50% less than necessary to break even	Efficiency gains are sufficient to break even	Efficiency gains are 50% more than necessary to break even
Multi-point FTR	-1.6	0	1.6
Two-node hybrid	-1.1	0	1.1

4.6.9 In order for the multi-point FTR to deliver productive efficiency gains of at least \$3.2M PV over ten years, it would be sufficient for it to reduce cost-to-serve by 0.01 c/kWh for 20% of load throughout New Zealand, beginning three years from now.

4.6.10 In order for the two-node hybrid to deliver productive efficiency gains of at least \$2.2M PV over ten years, it would be sufficient for it to reduce cost-to-serve by 0.005 c/kWh for 30% of load throughout New Zealand, beginning four years from now.

4.6.11 These calculations are sensitive to various parameters, including the modelling horizon and discount rate – however the scale of the reduction in cost-to-serve is the key uncertainty.

4.6.12 Note that the net benefit of either option (relative to the status quo) is likely to be substantially less than the Authority's estimate of the net benefit of introducing inter-island FTRs, which was \$14–25M (NPV over ten years).[22] This is consistent with the Authority's finding that inter-island price risk is more significant than within-island price risk.

4.6.13 The Authority considers that:

(a) it is highly likely that the multi-point FTR would deliver productive efficiency gains of at least $3.2M PV, equalling or exceeding the costs

(b) it is more likely that the multi-point FTR would deliver efficiency gains of at least $3.2M PV than that the two-node hybrid would deliver efficiency gains of $2.2M PV. The Authority bases this view on the analysis in Section 4.5 and Appendix F, which highlights that LRAs are not tradable and would not be so effective in enabling retailers to operate in new areas.

4.6.14 The Authority also considers that this cost-benefit analysis may understate the benefits of proceeding with an FTR solution, since it does not include the option value associated with the multi-point FTR (which allows more flexibility for future development than the two-node hybrid)

4.6.15 The multi-point FTR is therefore the Authority's preferred option at this stage. The Authority seeks feedback from submitters on this conclusion.

Q12. Do you agree that the multi-point FTR would produce a greater net benefit than any of the other options? If not, why not, and which option do you consider would produce the greatest net benefit?

[22] Section 3.7 of http://www.ea.govt.nz/dmsdocument/9986

Table 10 Estimated costs of introducing new FTRs or LRAs, relative to the status quo

	Multi-point FTR		***Two-node hybrid***	
Item	**Cost ($M)**	**PV ($M)**	**Cost ($M)**	**PV ($M)**
Development cost	No additional cost (the Authority’s contract with the FTR manager already provides for an annual review of the FTR allocation plan)	0	Costs would be incurred by the Authority and stakeholders in the process of developing the LRA concept to the Code amendment stage. Assume a total cost of $0.5M.	0.5
Implementation cost incurred by service providers	Total FTR manager costs	0.2	Total clearing manager costs	0.36
	Project implementation = 0.14 Audit = 0.019 Software licensing = 0.02 Non-functional testing = 0.02		Revision of invoices = 0.04 Develop, test and run LRA calculation and inputs = 0.18 Project implementation = 0.06 Potential changes to prudential system = 0.08	

	Multi-point FTR		*Two-node hybrid*	
Item	**Cost ($M)**	**PV ($M)**	**Cost ($M)**	**PV ($M)**
On-going analytical resource cost incurred by participants and the Authority	Assume eight organisations would each use an average of 0.5 FTE of additional resource (e.g. trader, portfolio analyst, financial accountant, market performance analyst) at $120K per FTE per year. Total is $480K per year. For PV calculations, defer the cost by 1 year.	3.0	Assume twenty organisations would each use an average of 0.1 FTE of additional resource (e.g. portfolio analyst, financial accountant, market performance analyst) at $120K per FTE per year. Total is $240K per year. For PV calculations, defer the cost by 2 years.	1.3
	Total:	**$3.2M**	**Total:**	**$2.2M**

5. If the Authority proceeds with the *multi-point* FTR, there will be design decisions to make

5.1 No Code amendment is necessary - The Authority can recommend design choices to the FTR manager

5.1.1 If (following consultation) the Authority concludes that the *multi-point FTR* is the option most consistent with its statutory objective, it will proceed to advise the FTR manager of this decision through a letter of expectation.

5.1.2 No Code amendment would be necessary to expand the FTR market. However, the Authority would take this opportunity to make (non-binding) recommendations to the FTR manager on how new FTR products should be designed.

5.1.3 The FTR manager could then consider the Authority's advice in its 2013 review of the FTR allocation plan. Under the contract this review is to be completed by October 2013, but that date could be pushed back if necessary.

5.1.4 To this end, this section of the paper sets out the Authority's provisional views on four key FTR design issues, and seeks feedback from stakeholders.

5.1.5 The issues discussed are:

(a) how many new FTR points should be added, and where they should be located

(b) whether nodes or hubs are preferable

(c) whether point-to-point FTRs are preferable to radial FTRs

(d) whether it is preferable to offer a full selection of options and obligations in both directions, or only a subset of these.

5.1.6 It is important to emphasise that the Authority has not made a firm decision to proceed with the *multi-point FTR* at this point. If information received from submitters led the Authority to conclude that a hybrid option was more consistent with its statutory objective, then it would initiate a new process to design the LRA component and determine what amendments to the Code would be required.

5.2 Based on statistical analysis, five to seven new FTR points may be appropriate

5.2.1 The Authority does not anticipate taking a firm view on how many new FTR points should be added or where they should be located, but sets out a strawman suggestion in this section to stimulate discussion.

5.2.2 The Authority suggests four "tiers" of FTR points (Figure 1):

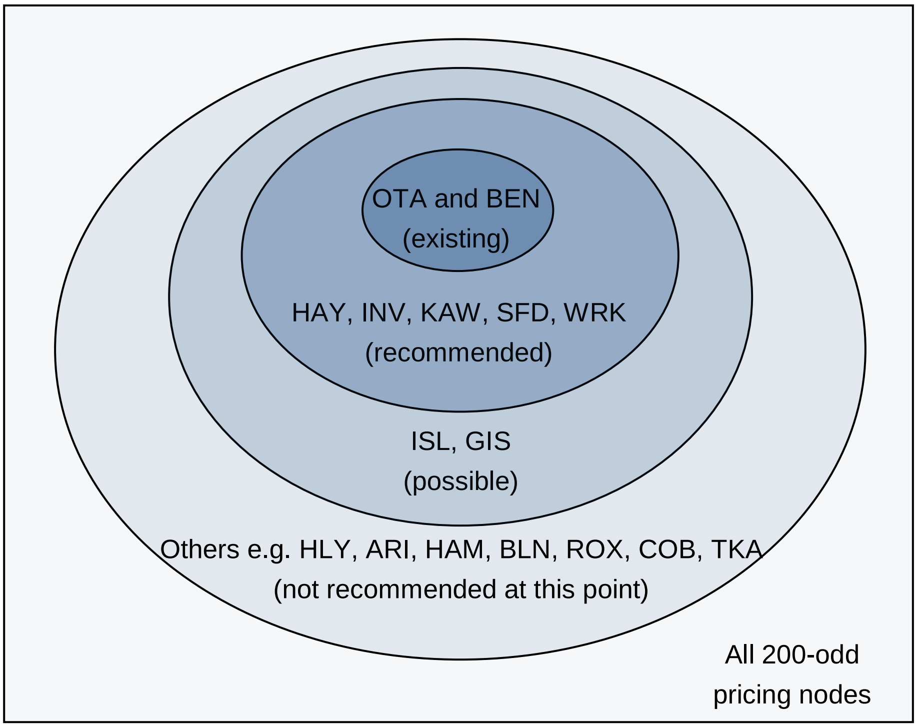
(a) OTA and BEN will be covered by the inter-island FTR

(b) HAY, Invercargill (INV), Kawerau (KAW), Stratford (SFD) and Wairakei (WRK) should probably be added in the near term

(c) Islington (ISL) and Gisborne (GIS) should perhaps also be added

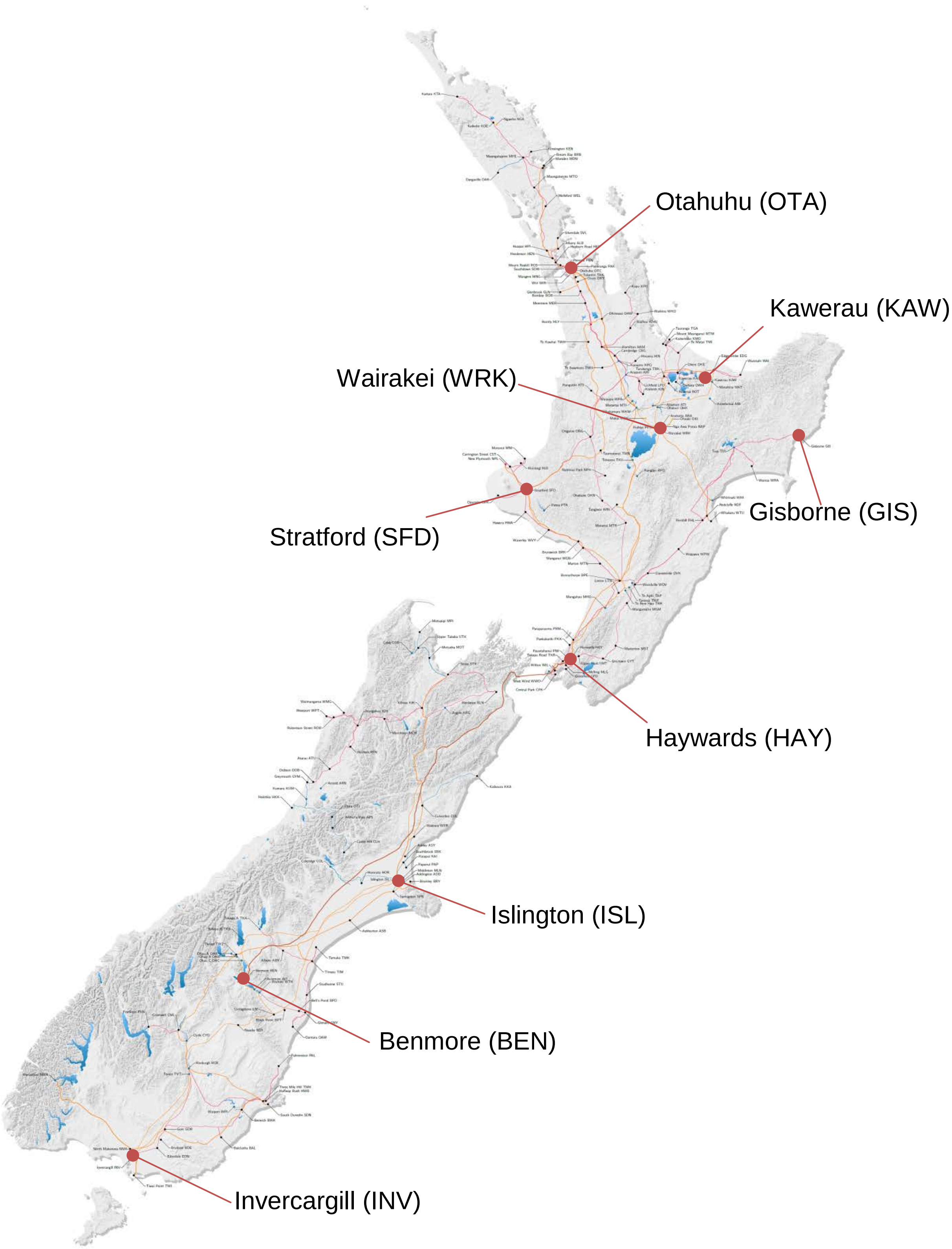
(d) there are various other nodes that *could* be added, such as Huntly (HLY), Arapuni (ARI), Hamilton (HAM), Blenheim (BLN), Roxburgh (ROX), Cobb (COB) and Tekapo A (TKA). However, such nodes might add relatively little value, and should therefore be added at a later date – if at all.

Figure 1 Existing and potential FTR points



5.2.3 The nine nodes in the top three tiers are mapped in Figure 2.

Figure 2 A potential set of nine FTR points



5.2.4 There would be valid alternatives to each of the above points. The benefit of an FTR node at KAW, for instance, would be to help participants manage LPR between the Bay of Plenty and other parts of the country – but it might well be possible to achieve this benefit using a different node in the region, such as Tarukenga (TRK), Tauranga (TGA), or a regional hub.

The Authority's reasons for suggesting four tiers of FTR points

5.2.5 On one hand, it seems preferable to have more FTR points rather than less, in order to maximise the level of locational hedge cover available to participants.

5.2.6 Each new FTR point added would improve hedge opportunities for participants at "nearby" nodes (i.e. nodes whose spot prices are correlated with spot prices at the new FTR point). It follows that the added value provided by a new FTR point would be high if it was "nearby" to nodes that:[23]

(a) had substantial load and/or generation

(b) were not themselves "nearby" to any other FTR point.

5.2.7 On the other hand, it seems preferable not to have too many FTR points – firstly to avoid undue complexity, and secondly to limit the scope for parties to use their energy market position to affect the value of FTRs in and out of outlying regions.[24]

5.2.8 As the number of FTR points increased, the FTR market would become:

(a) more complex to trade in – requiring participants to expend more resource if they are to take up the opportunities offered by the new FTR points

(b) more complex to monitor – requiring the Authority and participants to expend more resource in order to scrutinise behaviour in the FTR market.

5.2.9 Further, if FTR coverage was to extend to points in outlying regions of the grid with relatively limited transmission capacity and dominant local generators, then the relevant local generators might be able to derive

[23] A more precise description is provided in Appendix H.

[24] A third problem with increasing the number of FTR points might be that (in the absence of reconfiguration auctions) there would be a very limited market for secondary trading in some of the products created. (For instance, a party holding FTRs between Greymouth and Taumaranui would probably find it difficult to find a buyer if it decided to exit its position.) However, the FTR manager has advised that it intends to introduce reconfiguration auctions as a matter of priority, so supporting active secondary trading of FTRs need not be a concern.

financial advantage by using their energy market position to affect the value of FTRs in and out of the region. This would discourage (or outright prevent) other parties from acquiring these FTRs, and hence discourage retail competition. Some caution should therefore be applied in adding new points in outlying regions. (Appendix D discusses this issue further, noting that any inefficient outcomes identified could lead the Authority to consider amendments to the Code – for instance, seeking to restrict the proportion of FTRs over a single route that can be held by a single participant.)

5.2.10 Considering these competing drivers, the Authority's provisional preference would be a compromise that:

(a) provided participants with effective tools to manage the majority of LPR, but

(b) retained a reasonable degree of simplicity, and

(c) did not extend too far into the fringes of the grid.

5.2.11 The Authority has therefore carried out statistical analysis[25] to estimate how the level of hedge cover may improve as the number of FTR points increases. The analysis is based on historical prices between 2001 and 2012, on the basis that historical trends may be indicative of the level of future WIBR.

5.2.12 The results are summarised in Figure 3, and more detail is provided in Appendix H.

5.2.13 The statistical analysis[26] has already shown that a new FTR point in the LNI (such as a node at HAY) would provide significant benefit. Figure 3 shows that there could also be significant benefit in adding INV, KAW, SFD and WRK – and perhaps also a reasonable level of benefit in adding ISL and GIS – but relatively little benefit in adding other nodes.

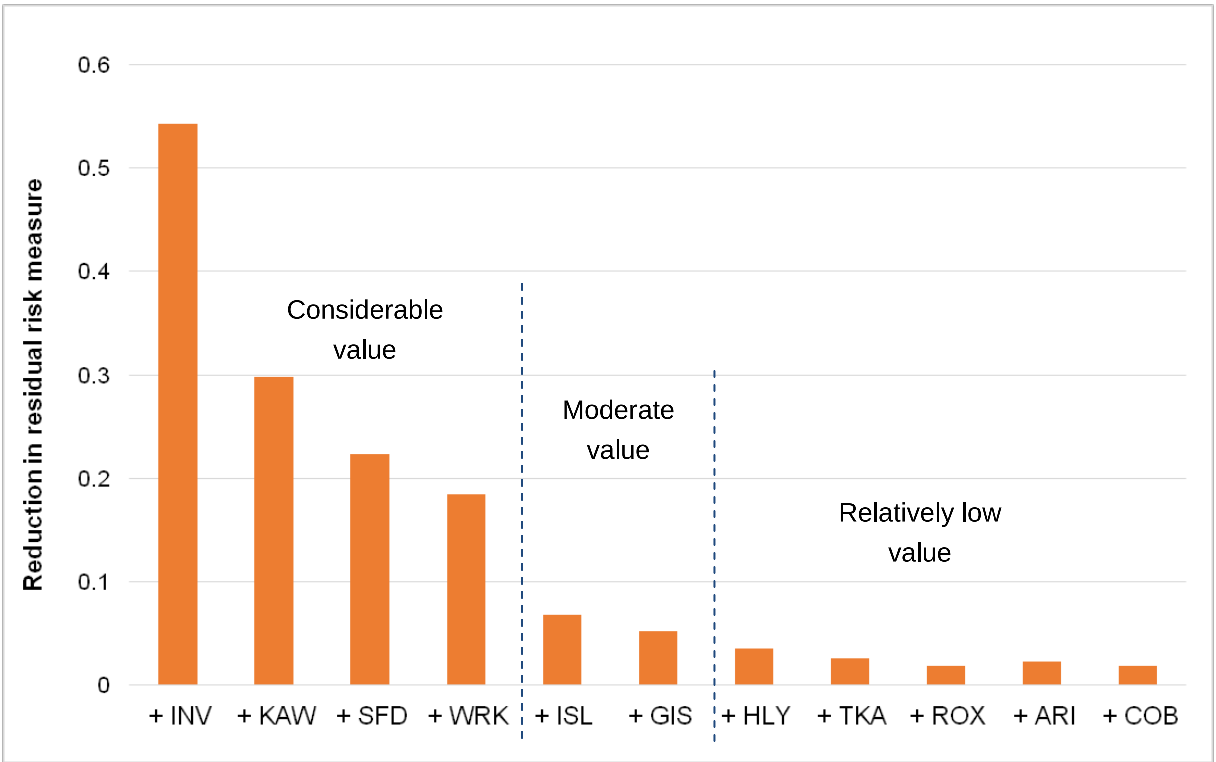
5.2.14 If the potential problems associated with adding new FTR points proved tractable, then more FTR points could be added at a later stage.

5.2.15 Notwithstanding the statistical analysis, the Authority will primarily be guided by stakeholder feedback on this issue. The FTR market is for the benefit of participants and it is important that it should include the nodes that participants require. Conversely, there is no point in adding a new FTR product if participants do not wish to trade it.

25 Within-island basis risk: quantifying the risk, available from http://www.ea.govt.nz/our-work/advisory-working-groups/lprtg/14feb13/

26 Ibid

Figure 3 Value added by each additional FTR point, *over and above* the value provided by OTA, BEN and HAY



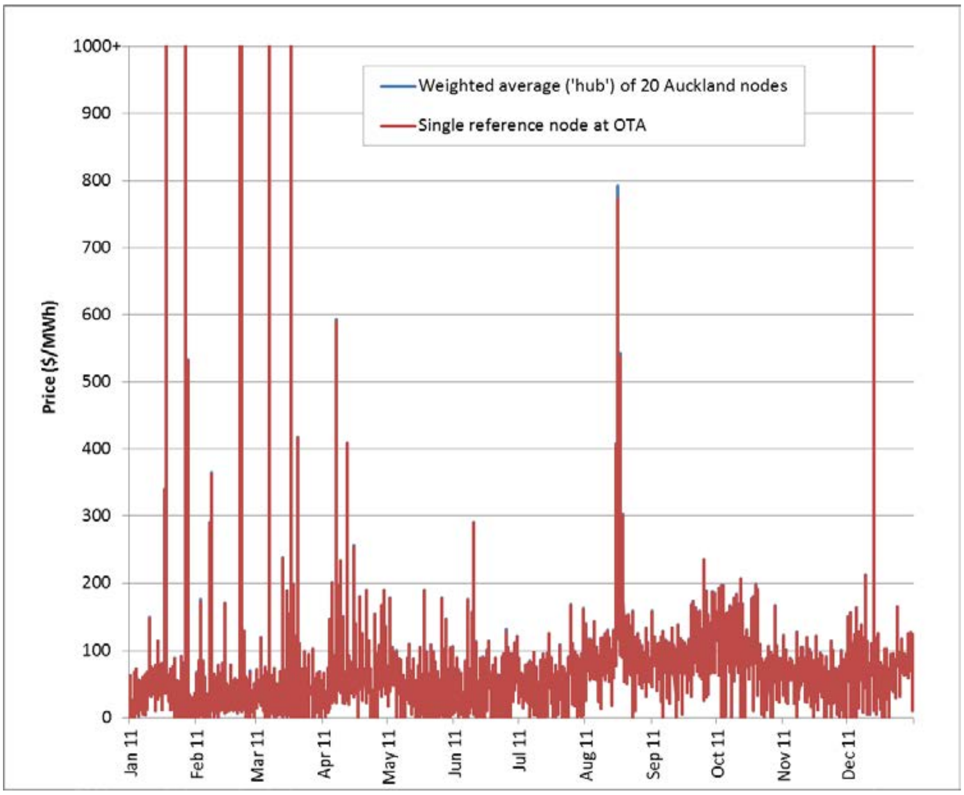
Q13.	**If the decision is to proceed with the *multi-point FTR*, which FTR points do you consider should be added at this point, and why?**

5.3 New nodes may be preferable to hubs

5.3.1 A hub price is a weighted average of spot prices at multiple nodes (with the weights being fixed, rather than varying in accordance with load or generation).

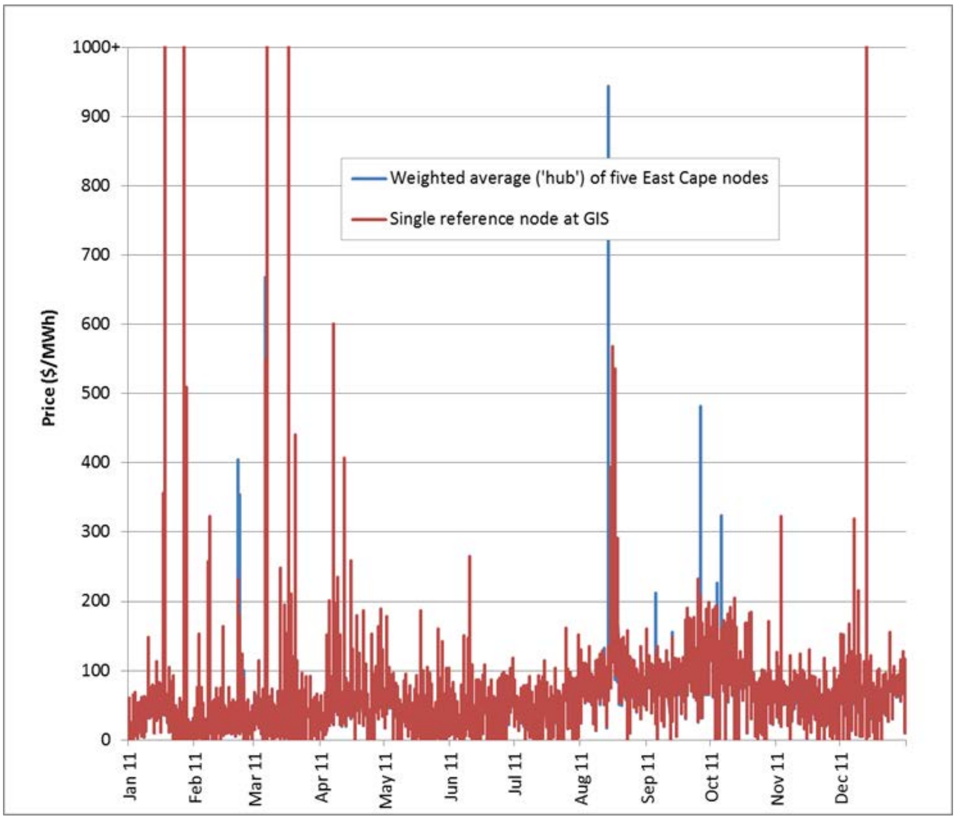
5.3.2 In regions where there is little WIBR, the price at a suitably weighted hub may be very similar to the price at a single reference node (Figure 4). However, in regions where there is more WIBR, the hub price may diverge more from the price at any single reference node (Figure 5).

Figure 4 Node price vs hub price – Auckland



(The two prices are nearly indistinguishable over 2011)

Figure 5 Node price vs hub price – East Cape



(In some trading periods the hub price substantially exceeds the reference node price)

5.3.3 The FTR manager advises that nodes and hubs would be equally easy to implement using existing software.

5.3.4 The Authority considers that it may be preferable to implement new FTR points as nodes rather than hubs, for simplicity.

5.3.5 However, the Authority appreciates that there may in some cases be technical reasons to use a hub instead. The FTR manager has indicated that if the parts of the transmission grid connecting a new FTR node to the rest of the grid were of limited capacity, then this might limit the amount of FTRs that could be sold. In such cases, using a regional hub could allow more FTRs to be offered.

Q14. Do you agree that, if the decision is to proceed with the multi-point FTR, the new FTR points should generally be nodes rather than hubs? If not, why not?

5.4 Point-to-point FTRs are preferable to radial FTRs

5.4.1 Under radial arrangements, the FTRs that would be available would extend from one or two central points to a larger number of points "in the provinces".

5.4.2 Under point-to-point arrangements, FTRs would be available between every pair of FTR points.

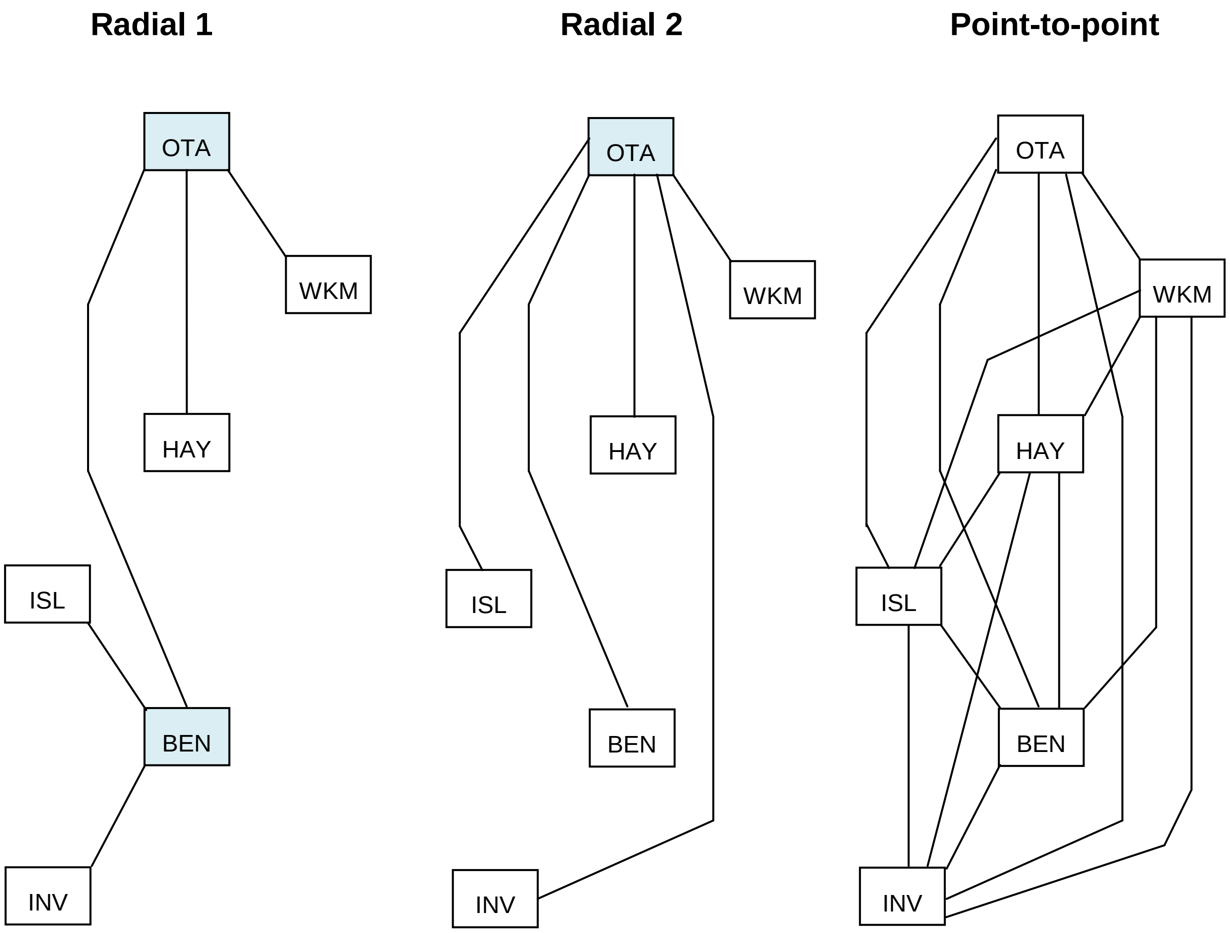
5.4.3 For instance, if there were FTR nodes at Otahuhu (OTA), Whakamaru (WKM), Haywards (HAY), Islington (ISL), Benmore (BEN) and Invercargill (INV), then the FTR products offered could be:

(a) OTA-WKM, OTA-HAY, OTA-BEN, BEN-ISL and BEN-INV *(one radial option)*

(b) OTA-WKM, OTA-HAY, OTA-ISL, OTA-BEN and OTA-INV *(another radial option)*

(c) OTA-WKM, OTA-HAY, OTA-ISL, OTA-BEN, OTA-INV, WKM-HAY, WKM-ISL, WKM-*BEN, WKM-INV, HAY-ISL,* HAY-BEN, HAY-INV, ISL-BEN, ISL-INV and BEN-INV *(point-to-point)*.

Figure 6 Radial and point-to-point FTRs



5.4.4 The FTR manager advises that point-to-point arrangements would be easier to implement using existing software, but that radial arrangements would also be viable.

5.4.5 The Authority considers that point-to-point FTRs may be preferable to radial FTRs, on the basis that allowing FTRs between any two points would make it easier for traders to obtain the portfolio they require.

5.4.6 The advantage of point-to-point arrangements would be that a participant that required cover between a particular pair of FTR points would be able to obtain that cover by buying a single product. Under radial arrangements, the participant might need to buy several products to get the same end result. Not only would this be less convenient, but there would be a risk that the participant would fail to obtain one of the products they needed, and would end up poorly hedged.

5.4.7 For instance, a participant with load at Islington (ISL) and generation at Stratford (SFD) would likely prefer to be able to buy a point-to-point FTR between SFD and ISL, rather than having to build it from a radial FTR between SFD and OTA, an inter-island FTR between OTA and BEN and a radial FTR between BEN and ISL. The latter option would require three times as many trades, and would expose the participant to WIBR if (for instance) they succeeded in buying FTRs from SFD to OTA and OTA to BEN but failed to obtain the last link of the chain, from BEN to ISL.

5.4.8 The disadvantage of point-to-point arrangements is that they create a much larger number of FTR products. Where N is the number of FTR points, the number of FTRs would grow in proportion to (N-1) under radial arrangements but in proportion to N(N-1) under point-to-point arrangements. As the number of FTR points increased, the FTR market would become:

(a) more complex to trade in

(b) more complex to monitor.

5.4.9 The Authority considers that, for moderate numbers of FTR points (e.g. less than ten), the advantages of point-to-point FTRs would probably outweigh the disadvantages. If the number of FTR points increased beyond that level, then there might be a case for moving to radial arrangements.

Q15. Do you agree that, if the decision is to proceed with the multi-point FTR, the new FTRs should be point-to-point rather than radial? If not, why not?

5.5 It would be preferable to provide a full selection of options and obligations in both directions

5.5.1 The difference between options and obligations is that:

(a) an option FTR is a right to receive price differences in a single direction only

(b) an obligation FTR is a combination of a right to receive price differences in one direction and a responsibility to pay price differences in the other direction.

5.5.2 FTRs between new points could include:

(a) obligations only

(b) options in one or both directions, or

(c) both obligations and options.

5.5.3 For example, a hypothetical radial design might provide:

(a) obligations and options between OTA and BEN (as currently), and

(b) options from each island reference nodes to several regional nodes. These options would pay out if the price at the regional node was higher than the price at the island reference node, but not vice versa. Such options could provide cover to buyers at or near the regional nodes.

5.5.4 The FTR manager advises that a full selection of options and obligations would be easier to implement using existing software, but that offering a limited selection would also be viable.

5.5.5 The Authority considers that it may be preferable to provide a full selection of options and obligations, in both directions, between each pair of nodes – in order to give traders more flexibility.

5.5.6 The advantage of providing a full selection of options and obligations would be that a participant that required cover in a particular direction (or in both directions) would be able to obtain that type of cover.

5.5.7 For instance:

(a) a party with load near a regional FTR node could purchase an obligation from the island reference node to the regional node

(b) a party with baseload generation near a regional FTR node could purchase an obligation from the regional node to the island reference node

(c) a party owning hydro generation, with quantity that varied along with the locational price difference, could purchase options in both directions. In wet periods, the option *from* the regional node would mitigate the effect of any export constraints from the region; in dry periods, the option *to* the island reference node would help to manage the generator's quantity risk.

5.5.8 The disadvantage of providing a full selection of options and obligations would be that there would be a larger number of FTR products, i.e. four products for each FTR route. As the number of FTR points increased, the FTR market would become:

(a) more complex to trade in

(b) more complex to monitor.

5.5.9 The Authority considers, however, that this disadvantage would be outweighed by the advantages of providing participants with more flexibility.

Q16.	**Do you agree that, if the decision is to proceed with the multi-point FTR, the new FTR products should include a full selection of options and obligations? If not, why not?**

6. There may be a need for further development in the longer term

6.1 None of the high-level options considered would completely eliminate WIBR

6.1.1 The four high-level options considered would each address some types of WIBR faced by participants, but none of them would eliminate WIBR entirely.

6.1.2 The residual level of WIBR experienced by participants will depend on the extent and nature of locational price variability, the development of any new FTRs and/or LRAs, and the progress of other initiatives such as the WAG's pivotal pricing project.

6.1.3 The Authority will continue to monitor WIBR. If WIBR continues to inhibit retail competition in affected areas, the Authority will consider taking further steps to assist participants to manage it.

6.2 The Authority proposes a longer-term roadmap for addressing WIBR

6.2.1 This section sets out the Authority's proposed roadmap for addressing WIBR, in order to:

(a) explain to participants how the Authority plans to proceed in the longer term

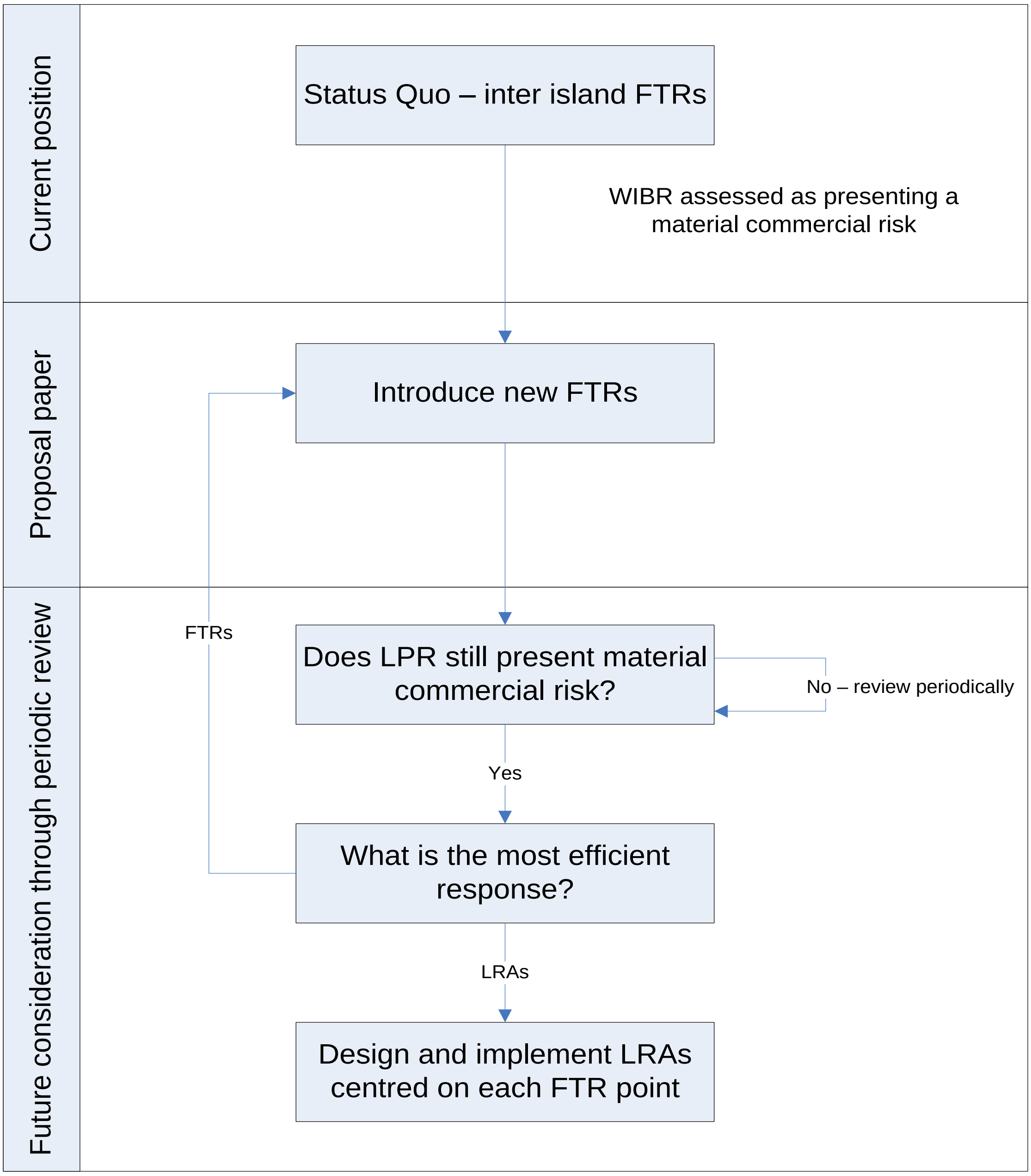
(b) seek feedback on the proposed approach.

6.2.2 The proposed roadmap is conditional on the Authority proceeding with the multi-point FTR option. If (following consultation) the Authority decides to take a different course, it will revise the roadmap accordingly.

6.2.3 The proposed roadmap is set out in Figure 7.

Q17. Do you agree that, if the decision is to proceed with the multi-point FTR, the Authority should proceed according to the roadmap set out in Figure 7? If not, how should the Authority proceed?

Figure 7 The Authority's proposed roadmap



6.2.4 In determining the most efficient response (if any) to residual WIBR, the Authority would consider factors including:

(a) the extent of locational price variability, the nodes affected and whether it was dominated by spikes or tidal flows

(b) the level of retail competition in affected regions

(c) the level of uptake of FTRs

(d) the extent to which LCE was available to fund LRAs.

6.2.5 The Authority would also consider developing objective criteria for adding new FTR nodes and removing existing FTR nodes in future years.

6.2.6 Criteria for adding a new FTR node could be based on:

(a) the amount of load and/or generation at or near the node

(b) the level of correlation of prices at the node with those at existing FTR nodes (a low level of correlation would support adding the new FTR node).

6.2.7 Criteria for removing an existing FTR node could be based on:

(a) the level of FTR trading activity at that node over an extended period

(b) the cost of continuing to offer FTR products at that node.

Q18. Do you agree that, if the decision is to proceed with the multi-point FTR, the Authority should develop objective criteria for adding and removing FTR nodes? What should be taken into account in developing these criteria?

6.3 It may eventually be appropriate to review the split between FTR and non-FTR LCE

6.3.1 Under existing arrangements, LCE is divided into two streams (Figure 8):

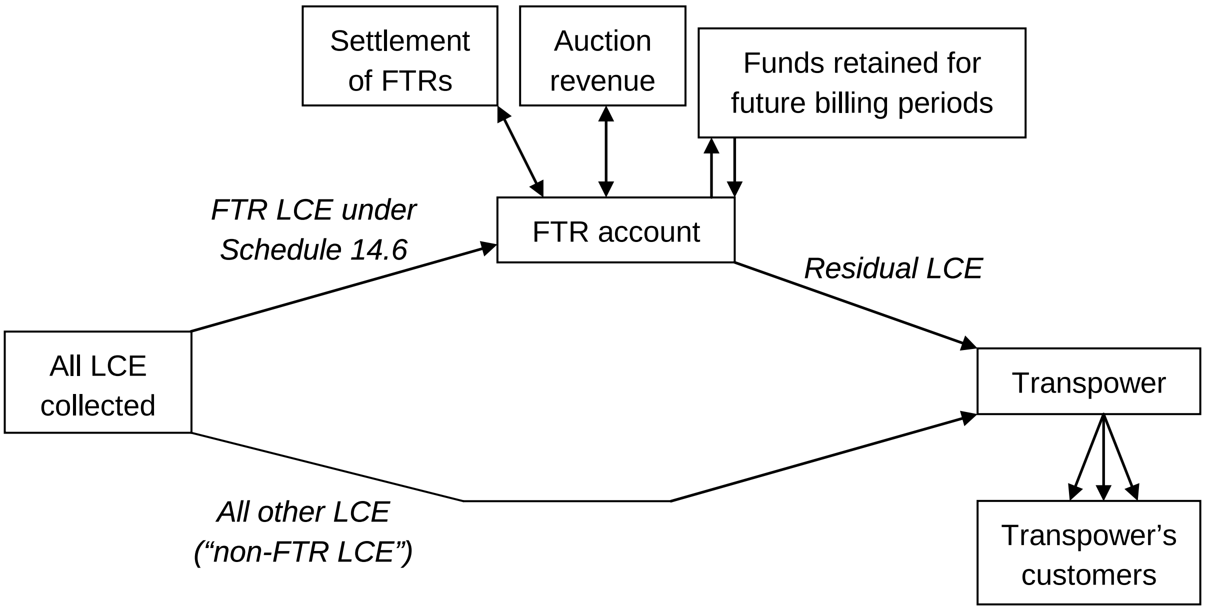
(a) a portion of LCE (denoted “FTR LCE” in this paper) is calculated using the methodology set out in Schedule 14.6 of the Code, and is paid into the FTR account to support the revenue adequacy of FTRs

(b) the remaining LCE (“non-FTR LCE”) is paid to Transpower for distribution to its customers.[27]

6.3.2 Transpower also receives (for distribution to its customers) any “residual LCE”. This is the surplus from the FTR account – i.e. any funds that are neither required to settle FTRs for the current billing period nor retained to settle FTRs in a future billing period (under clause 13.249(6) of the Code).

[27] Transpower’s current methodology for distributing these rentals to its customers is set out at (https://www.transpower.co.nz/sites/default/files/publications/resources/transmission-rentals-2008.pdf)

Figure 8 LCE is divided into two streams



6.3.3 Schedule 14.6 of the Code uses a mathematical formula to identify FTR LCE as the rentals arising on the HVDC plus rentals generated by (North Island) AC constraints (including losses, thermal and security constraints) in proportion to their contribution to a maximum FTR flow.

6.3.4 The method set out in Schedule 14.6 was designed to be "future-proof" – it would still work if new FTR nodes or hubs were added. However, even with two nodes, the method is complex and partly subjective. Increasing the number of FTR points would compound this problem.

6.3.5 These arrangements were originally intended[28] to strike a balance between:

(a) supporting the revenue adequacy of FTRs

(b) leaving a portion of LCE available to fund future FTRs or LRAs.

6.3.6 If and when new FTRs were introduced, there might be a case to cease using the method set out in Schedule 14.6, because:

(a) non-FTR LCE would become a much lower proportion of total LCE, to the extent that it might no longer be worth the effort of setting it aside

(b) the Authority might be in a position to determine that:

(i) WIBR no longer presented a material commercial risk, or

[28] See para 3.4.121 of http://www.ea.govt.nz/dmsdocument/9986

(ii) FTRs would be a more efficient response than LRAs to manage any remaining commercial risk, or

(iii) any future LRAs could be "unfunded" (i.e. two-sided LRAs in which all payments to participants were funded by payments *from* other participants).

6.3.7 The Authority might therefore consider other options such as:

(a) paying all LCE into the FTR account[29]

(b) paying all HVDC and interconnection rentals into the FTR account

(c) paying some (large) fixed percentage of LCE into the FTR account.

6.3.8 Under all these options, residual LCE would still be passed to Transpower for distribution to its customers.

6.3.9 Increasing the proportion of LCE paid into the FTR account would increase the revenue adequacy of FTRs (or, equivalently, allow a greater amount of FTRs to be issued while maintaining the same level of revenue adequacy).

6.3.10 The Authority would formally consult with stakeholders before making any such change, and would be guided by the CAPs in deciding what approach to follow.

[29] This is the option that was originally favoured by Transpower – see http://www.ea.govt.nz/dmsdocument/10291

Appendix A Format for submissions

Number	Question	Response
Q1	Do you agree that the Authority has characterised the problem of WIBR correctly? If not, how could the problem be better described?	
Q2	Do you agree that these four options are an appropriate shortlist? If not, are there other options that should be considered?	
Q3	Do you agree that the four options in Table 2 need not be considered at this stage? If not, which of them should be considered and why and what other options should be considered and why?	
Q4	Do you agree that the two-node hybrid option has been characterised correctly? If not, how could it be better described?	
Q5	Do you agree that the three-node FTR option has been characterised correctly? If not, how could it be better described?	
Q6	Do you agree that the three-node hybrid option has been characterised correctly? If not, how could it be better described?	
Q7	Do you agree that the multi-node FTR option has been characterised correctly? If not, how could it be better described?	
Q8	Do you agree that all four high-level options are feasible? If not, why not	
Q9	Do you agree that all four options would avoid distortion to price signals? If not, why not?	

Q10	Do you agree that the criteria in Table 7 are reasonable and roughly equal in priority? If not, why not? Should other criteria relating to competition, reliability or efficiency be considered?	
Q11	Do you agree that the multi-point FTR would promote the Authority's statutory objective most effectively? If not, why not, and which option do you think would most support the statutory objective?	
Q12	Do you agree that the multi-point FTR would produce a greater net benefit than any of the other options? If not, why not, and which option do you consider would produce the greatest net benefit?	
Q13	If the decision is to proceed with the *multi-point FTR*, which FTR points do you consider should be added at this point, and why?	
Q14	Do you agree that, if the decision is to proceed with the multi-point FTR, the new FTR points should generally be nodes rather than hubs? If not, why not?	
Q15	Do you agree that, if the decision is to proceed with the multi-point FTR, the new FTRs should be point-to-point rather than radial? If not, why not?	
Q16	Do you agree that, if the decision is to proceed with the multi-point FTR, the new FTR products should include a full selection of options and obligations? If not, why not?	
Q17	Do you agree that, if the decision is to proceed with the multi-point FTR, the Authority should proceed according to the roadmap set out in Figure 7? If not, how should the Authority proceed?	

Q18	Do you agree that, if the decision is to proceed with the multi-point FTR, the Authority should develop objective criteria for adding and removing FTR nodes in future years? What should be taken into account in developing these criteria?	

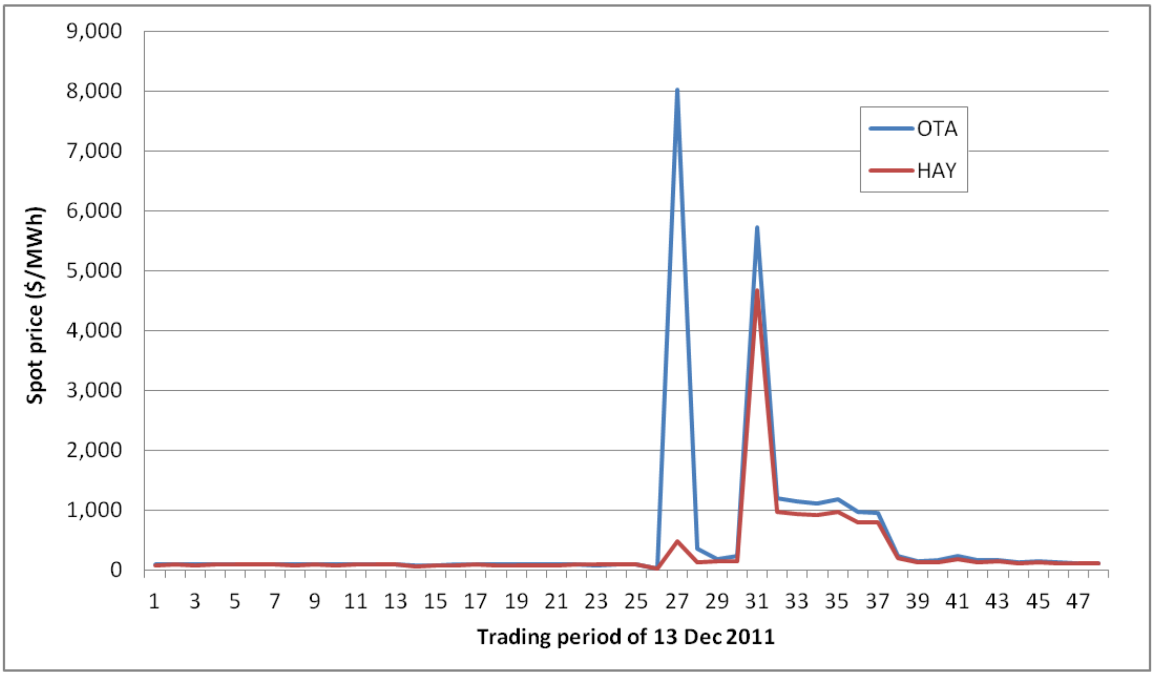
Appendix B Examples of locational price differences

B.1 This Appendix demonstrates some of the ways in which locational price differences can arise in the New Zealand spot market for electricity.

Locational price differences can arise from a capacity shortfall

B.2 Figure 9 shows a locational price spike associated with capacity shortfall (specifically, the AUFLS event of December 2011).

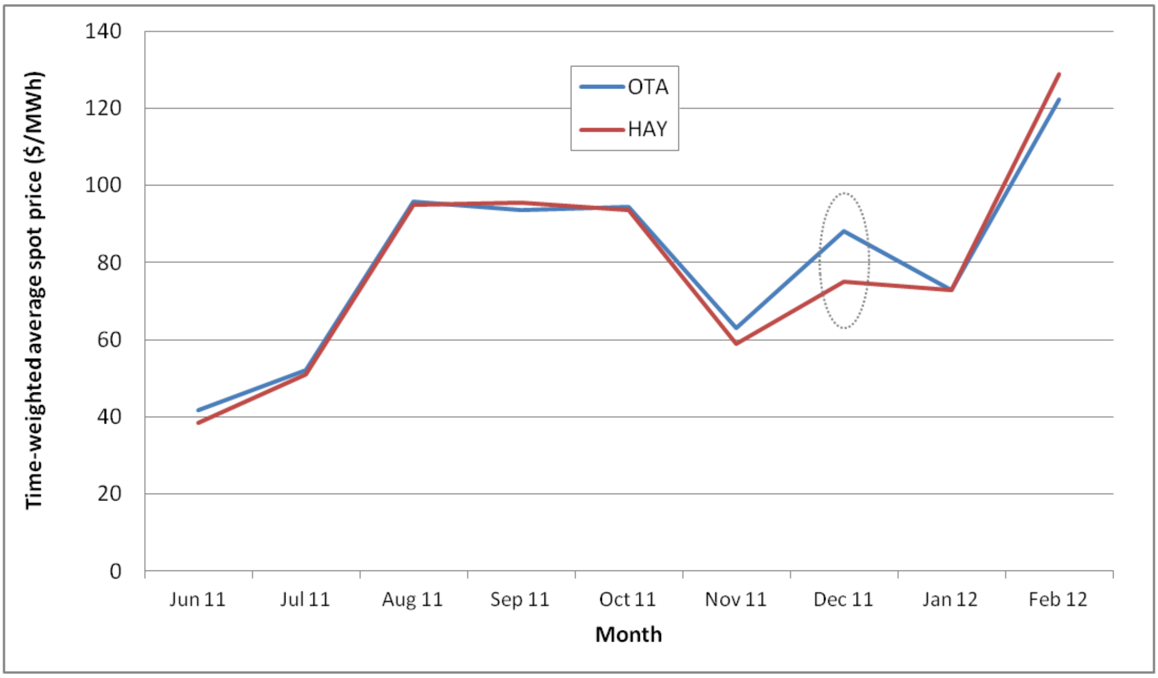
Figure 9 Locational price differences associated with capacity shortfall



B.3 Trading period 27 caused a $5/MWh uplift in the monthly mean price at OTA, relative to HAY.

B.4 This, along with other events, resulted in a locational difference in monthly mean price (Figure 10).

Figure 10 Effect of locational price differences associated with capacity shortfall on monthly mean prices

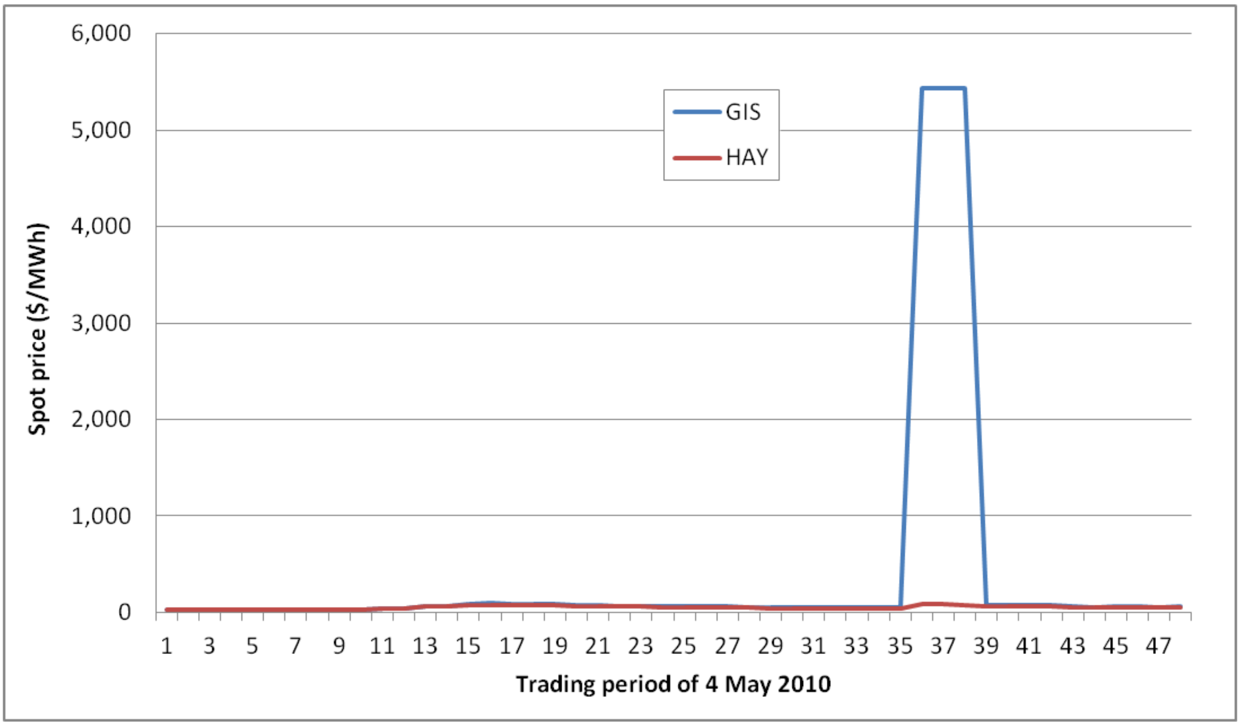


Locational price differences can arise from pivotal supplier situations

B.5 Figure 11 shows a locational price spike associated with a pivotal supplier situation in the East Cape region.

B.6 In trading periods 36 through 38, there was price separation between some East Cape nodes and the rest of the country.

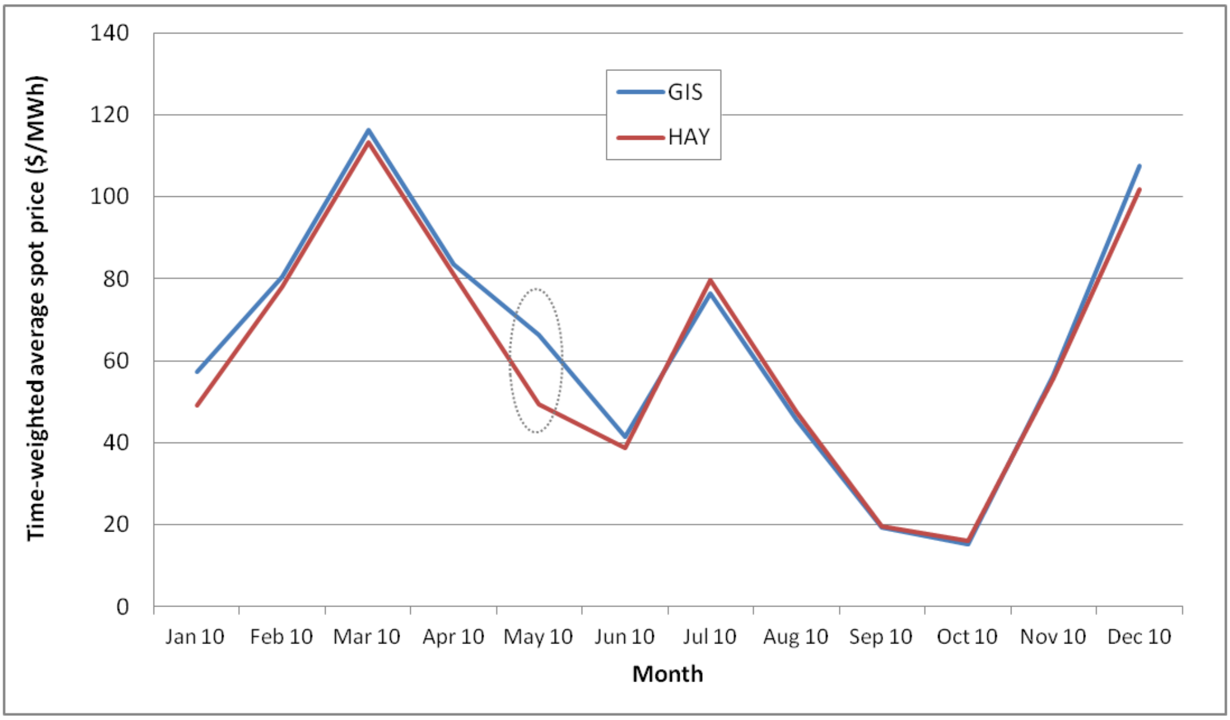
Figure 11 Locational price differences associated with a pivotal supplier situation



B.7 These three trading periods caused a $11/MWh uplift in the monthly mean price at Gisborne, relative to Haywards.

B.8 This, along with other events, resulted in a locational difference in monthly mean price (Figure 12).

Figure 12 Effect of locational price differences associated with a pivotal supplier situation on monthly mean prices

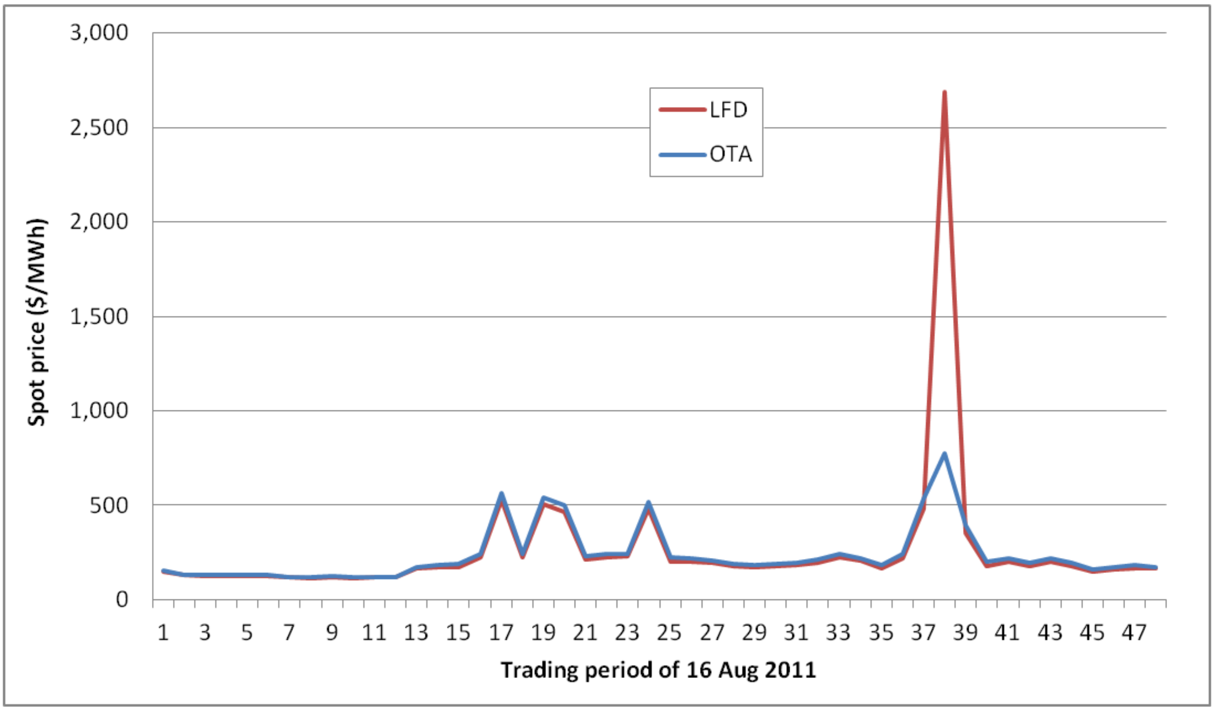


Locational price differences can arise from high spring washer price situations

B.9 Figure 13 shows a locational price spike associated with a high spring washer situation in the Waikato.

B.10 In trading period 38, there was price separation between some nodes (notably Lichfield (LFD)) and the rest of the country.

Figure 13 Locational price differences associated with a high spring washer price situation



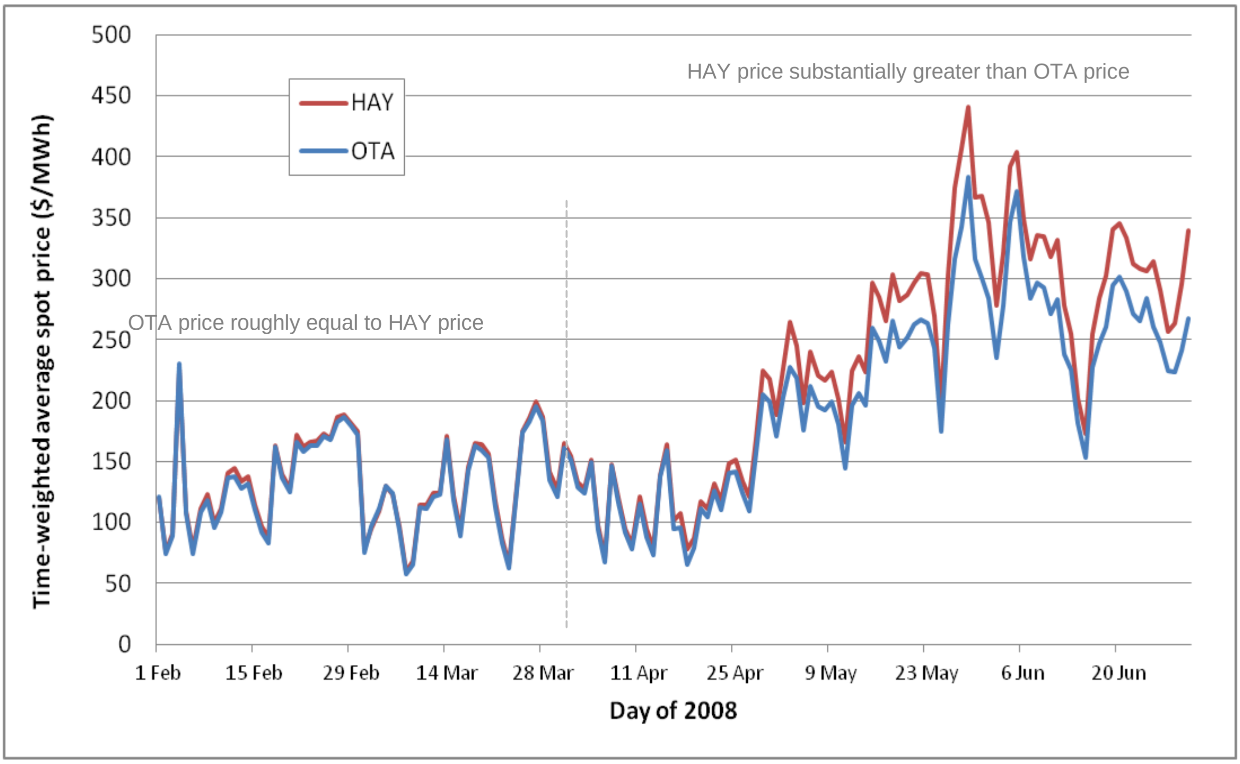
Locational price differences can arise from extended dry sequences

B.11 Figure 14 shows a locational price spike associated with the 2008 dry sequence.

B.12 During a period of predominantly south flow, the price in the lower North Island was higher than that in the upper North Island.

B.13 Such events are also associated with high wholesale prices nationwide, and with quantity risk for some hydro generators.

Figure 14 Locational price differences associated with a dry sequence



Appendix C Inter-island FTRs are to be introduced in 2013

C.1 In order to assist participants to manage LPR, the Authority is introducing inter-island FTRs. These FTRs are based on the price difference between OTA and BEN, and will therefore assist in managing the price risk between those locations, which includes:

(a) inter-island price risk between BEN and Haywards (HAY)

(b) within-island price risk between HAY and OTA.

C.2 The first FTR auctions are scheduled for 12 and 19 June 2013, offering products covering the July 2013 FTR period, with each auction being for 50% of the available FTR capacity. There will be two auctions every month, with the FTR horizon increasing over time (reaching two years by June 2014).[30]

C.3 The payouts of these FTRs are based on the full difference between prices at the two locations, including both the loss and constraint effects. Four products are offered – an option and an obligation in each direction.

C.4 Each FTR contract has a duration of one calendar month (though longer strips may be offered in future). FTRs are offered in units of 0.1 MW.

C.5 The FTR manager has published a policy on the FTR grid,[31] designed to set the volume of FTRs made available so as to deliver the likelihood of revenue adequacy prescribed in the FTR allocation plan. For each auction, this policy will be applied to the grid owner's forecast grid and outages for the FTR period to set the available FTR capacity.

C.6 FTR payouts will come from an FTR account which is funded by FTR LCE and FTR auction revenues. Any shortfall in revenue to meet FTR payments will be managed by scaling.

C.7 As set out in Schedule 14.6 of the Code, the FTR LCE amount is all rentals arising on the HVDC, plus rentals generated by (North Island) AC constraints (including losses, thermal and security constraints) in proportion to their contribution to a maximum FTR flow.

C.8 Non-FTR LCE, and residual LCE, will be paid to Transpower for distribution to its customers.[32] Residual LCE is the surplus from the FTR account – i.e. any funds that are neither required to settle FTRs for the

[30] http://ems.co.nz/ftr/ftrlibrary/ftr-policy-ftr-calendar---300.pdf

[31] http://ems.co.nz/ftr/ftrlibrary/ftr-grid-and-auction-data-pol.pdf

[32] Transpower's current methodology for distributing these rentals to its customers is set out at (https://www.transpower.co.nz/sites/default/files/publications/resources/transmission-rentals-2008.pdf)

current billing period nor retained to settle FTRs in a future billing period (under clause 13.249(6) of the Code).

C.9 The FTR manager will consult with the industry in 2013 on the variations to the FTR allocation plan, including:

(a) any recommendations made by the Authority

(b) secondary markets including reconfiguration auctions to enable FTR holders to offer their FTR back into the auction with a reserve price, which FTR participants have signalled strongly should be a priority

(c) other possible market developments, for example those listed in the FTR manager's "An introduction to the New Zealand FTR market".

C.10 Key references include:

(a) Subpart 6 of Part 13, and Schedules 13.5, 13.6 and 14.6, of the Code, which provide for FTRs[33]

(b) the FTR manager's FTR allocation plan[34]

(c) the FTR manager's FTR policies and "Introduction to the New Zealand FTR market".[35]

[33] http://www.ea.govt.nz/act-code-regs/code-regs/the-code/

[34] http://ems.co.nz/ftr/ftrallocationplan

[35] http://ems.co.nz/ftr/ftrlibrary

Appendix D Effect of FTRs and LRAs on incentives in the energy market, and vice versa

D.1 This Appendix discusses four related but distinct issues, which have been grouped in the past under the general heading of "market power":

(a) the effect of LRAs on the incentive on a locally pivotal supplier to influence the spot price

(b) the effect of FTRs on the incentive on a locally pivotal supplier to influence the spot price

(c) the extent to which a participant's energy market position may affect the value they could derive from an FTR (and hence the price they would be prepared to pay for it)

(d) the extent to which the allocation of residual LCE could affect the value that a participant could derive from an FTR (and hence the price they would be prepared to pay for it).

Key references

D.2 Readers are directed to the following references:

(a) the discussion of market power with LRAs in "Locational Hedging Options for New Zealand: Issues and Options" (EGR Consulting)[36]

(b) "Exploring the Strategic Behaviour of FTR Holders with Market Power" (Stochastic Optimization Ltd)[37]

(c) minutes of LPRTG's discussion of the above paper[38]

(d) "Market Power Incentives from Local Hedging" (Paradox Strategic Advisors)[39]

(e) minutes of LPRTG's discussion of the above paper[40]

(f) "Why FTR trading in the New Zealand electricity market is a bad idea" (David Reeve)[41]

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[36] See Appendices 6 and 7 of www.ea.govt.nz/dmsdocument/976

[37] http://www.ea.govt.nz/dmsdocument/8295

[38] Section 4 of http://www.ea.govt.nz/dmsdocument/8779

[39] http://www.ea.govt.nz/dmsdocument/6430

[40] Section 6 of http://www.ea.govt.nz/dmsdocument/7135

[41] http://www.ea.govt.nz/dmsdocument/2478

(g) the discussion of market power in the Authority's consultation paper *"Managing locational price risk proposal"*[42]

(h) submissions on the above paper.[43]

D.3 Readers will note that, despite the extensive analysis carried out in recent years, a consensus has not yet been reached.

The effect of LRAs on the incentive on a locally pivotal supplier to influence the spot price

D.4 A locally pivotal supplier has the ability to increase the local spot price. A locally *net* pivotal supplier has both the ability and the short-term incentive to do so.[44]

D.5 It has been suggested that LRAs would increase the incentive faced by a pivotal supplier to increase the local price. Without the LRA, the supplier might be deterred from doing so because they could not be sure that they were *net* pivotal – so any increase in their local generation receipts might be more than countered by an increase in their local purchase costs. With the LRA in place, the supplier would no longer be deterred, because they could be confident that any increase in the local spot price would have little effect on their local purchase costs. All pivotal suppliers would effectively become *net* pivotal.

D.6 The counter-argument is that a pivotal (but not *net* pivotal) supplier already has an incentive to increase the local price, even without the LRA. While they may lose out in the short term, they can recoup their losses in the longer term by raising contract prices. From this viewpoint, the LRA makes the situation no worse.

D.7 LRAs would also change the *consequences* of an increase in the local spot price. Once LRA payouts were taken into account, the price increase would be spread across all load in the LRA zone, rather than being concentrated in the constrained region. This would reduce the impact on local retail competition, but might have a more dilute impact on retail competition throughout the LRA zone.

D.8 The Authority concludes that the net impact that LRAs would have on competition and efficiency (with regard to pivotal supplier situations) is uncertain.

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42 Section 5.10 of http://www.ea.govt.nz/dmsdocument/8139

43 Collated in pages 78-83 of http://www.ea.govt.nz/dmsdocument/8747

44 See e.g. http://www.ea.govt.nz/dmsdocument/13478

D.9 However, any adverse effects:

(a) might be alleviated by the outcomes of the WAG's pivotal pricing project

(b) could also be addressed through transparency and market monitoring.

D.10 This supports the Authority's view that "the effect on incentives faced by locally pivotal suppliers need not be a decisive consideration when considering whether to introduce LRAs" (para 4.3.5).

The effect of FTRs on the incentive on a locally pivotal supplier to influence the spot price

D.11 The effect of a participant's FTR holdings on its energy market incentives would depend on the nature of those holdings.

D.12 A locally pivotal supplier may be:

(a) *less* incentivised to increase the local spot price, if it holds obligation FTRs *out of* the constrained region

(b) *more* incentivised to increase the local spot price, if it holds FTRs *into* the constrained region. [45]

D.13 The former position would be the pivotal supplier's "natural position" and would reduce the volatility of its returns.

D.14 The latter position would be provocative. Other participants would interpret it as showing intent to capitalise on a pivotal position, and would likely seek to hedge themselves (either using FTRs or some other form of cover).

D.15 FTRs would assist participants to manage the risks associated with retailing in a region in which there was a locally pivotal supplier. Purchasing option and/or obligation FTRs into the region could considerably reduce the risk – though a reduced level of LPR would remain at times when retail load exceeded FTR cover.

D.16 However, the usefulness of FTRs for this purpose would depend on them being available at a reasonable price – see the following section.

D.17 The Authority concludes that the net effect of FTRs on pivotal supplier situations is uncertain. However, any adverse effects:

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[45] SOL (2010) describes an analogous situation in which a supplier in an export-constrained region, holding FTRs *out of* the constrained region, would have an incentive to increase output and collapse the local spot price (possibly resulting in inefficient dispatch).

(a) might be alleviated by the outcomes of the WAG's pivotal pricing project

(b) would be open to scrutiny by other participants – given that FTR holdings will be a matter of public record

(c) could be addressed through market monitoring. Any inefficient outcomes identified could lead the Authority to consider amendments to the Code (for instance, seeking to bar participants from using FTRs to make a locally long physical position even longer).

D.18 This supports the Authority's view that "the effect on incentives faced by locally pivotal suppliers need not be a decisive consideration when considering whether to introduce new FTRs" (para 4.3.5).

The extent to which a participant's energy market position could affect the value they could derive from an FTR

D.19 Different parties can derive different value from a given FTR product. A supplier may have the ability to use their energy market position to:

(a) increase the value of an FTR out of a region (by collapsing prices within the region)

(b) increase the value of an FTR into a region (by elevating prices within the region).

D.20 Since such suppliers are able to derive more value from the FTR than other parties, they are in a position to pay a higher price for the product, and will likely end up holding more of the offered quantity.

D.21 This should not be characterised as an issue of market power in the FTR auction. No single participant has the ability to elevate the price of an FTR product to an arbitrary level, as a pivotal supplier does in the energy market.[46] Rather, the issue is that a locally dominant supplier in the energy market may be incentivised to outbid all other parties. If other parties cannot obtain a FTR product at a reasonable price, the product will not achieve its objective of supporting competition.

D.22 This problem was cast in strong terms by Bushnell (1999):[47] *"It is important to note the potential use of [FTRs] as an instrument for exercising market power will increase their value to those firms that can use them to that end. Any open market or auction process that is used to distribute these rights can therefore result in more rights flowing to the firms that can abuse them the most."*

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[46] Except by bidding a very high price for the full offered quantity of the FTR product, which will generally leave the high bidder much worse off.

[47] www.ucei.berkeley.edu/PDF/pwp062.pdf

D.23 In the context of inter-island FTRs, the Authority considered that the problem of locally dominant suppliers was manageable (given market monitoring), since no participant is dominant at an island level (except transiently on infrequent occasions). This was seen as one of the major advantages of the two-node regime.[48]

D.24 However, if more FTR points are added, the problem of locally dominant suppliers may become more material – particularly if the new FTR points are located in outlying regions of the grid, with relatively limited (import or export) transmission capacity and dominant local generators.

D.25 The Authority concludes that this issue should be addressed:

(a) through transparency and market monitoring. Any inefficient outcomes identified could lead the Authority to consider amendments to the Code (for instance, seeking to restrict the proportion of FTRs over a single route that can be held by a single participant)

(b) by adding only a moderate number of new FTR points in the first instance, so that FTR market monitoring remains a tractable task (para 5.2.8)

(c) by applying caution in creating new FTR points in outlying regions of the grid (para 5.2.9).

The extent to which the allocation of residual LCE could affect the price that a participant would be willing to bid for an FTR

D.26 Concerns have been raised in the past that the way in which residual LCE is allocated could lead to distortions in the FTR auction.

D.27 If the allocation of residual LCE was not considered, then the net benefit derived by a participant from purchasing a particular FTR product would equal the benefit stemming from owning the product minus the purchase cost.

D.28 However, participants that can purchase FTRs are also Transpower customers and can receive residual LCE from Transpower. The net benefit of purchasing a particular FTR product, then, is the benefit stemming from owning the product, minus the purchase cost, *plus* the proportion of the increase in the cost of the FTR (as the result of the participant's bid being successful) that returns to the same participant as a reduction in transmission charges.[49]

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[48] http://www.ea.govt.nz/dmsdocument/9986

[49] For instance, if Participant A was eligible to receive 20% of the residual LCE from a particular FTR, and the FTR would have sold to another party for $10,000 but instead Participant A bought it for $13,000, then Participant A would effectively receive a rebate of ($13,000 - $10,000) x 20% = $600.

D.29 If a participant expected to be allocated a substantial portion of the purchase cost of a particular FTR product (as residual LCE), then that participant might be incentivised to outbid all other parties. This could prevent other parties from obtaining the quantity of the FTR product they require at a reasonable price. As a result, the product might not achieve its objective of supporting competition.

D.30 Transpower has published its current methodology for distributing residual LCE to connection, interconnection and HVDC charge payers.[50] The Authority published an information paper "Allocation of residual loss and constraint excess post introduction of FTRs" in 2012,[51] setting out that this methodology largely avoids distorting the FTR auction.

D.31 As a result, the Authority concludes that the allocation of residual LCE need not be a consideration in deciding whether to introduce new FTRs.

D.32 In any future review of the allocation of residual LCE (i.e. under the TPM project), the Authority would consider the implications for the competitiveness of the FTR market.

50 https://www.transpower.co.nz/sites/default/files/publications/resources/transmission-rentals-2008.pdf

51 www.ea.govt.nz/dmsdocument/13357

Appendix E A potential LRA design

A two-node hybrid design

E.1 This section briefly describes how the LRA part of the two-node hybrid option described in Section 3.4 could be designed. It is consistent with the design parameters set out in Table 3.

E.2 The central element of the design is the way in which LRA payouts (or amounts owing) would be calculated.

E.3 The LRA payout for purchaser *p* at node *n* in month[52] *m* would be calculated as follows:[53]

$$PAY(p,n,m) = AQ(p,n) \times [Pr(n,m) - AMLF(n,Ref(n)) \times Pr(Ref(n),m) \times k(m)]$$

where:

AQ(p,n) is the average quantity of energy purchased by purchaser *p* at node *n* over some previous time period (see below for more detail as to how this quantity could be calculated)

Pr(n,m) is the mean spot price at node *n* in month *m*

AMLF(n,n') is the averaged marginal loss factor between nodes *n* and *n'* over the long term (see below for more detail as to how AMLF could be estimated)

Ref(n) is the reference node of the island in which node *n* is located (i.e. either OTA or BEN)

k(m) is chosen so that $\sum_{p,n} PAY(p,n,m)$ is equal to the portion of LCE available to fund LRAs in month *m*.[54]

E.4 Payouts would be straightforward to calculate, since they could be determined at the monthly level (rather than requiring a separate calculation for each individual trading period).

E.5 This LRA scheme has been modelled and applied to calculate what LRA payouts would have been in the 2010, 2011 and 2012 years, and how this could have affected participant positions. The analysis has been carried out on an "all else being equal" basis – i.e. assuming no change to bids,

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52 Assuming a monthly settlement period for convenience – the approach generalises to any settlement period.

53 Alternatively the LRA payout could be separated between times of day – i.e. with *AQ, Pr,* and *AMLF* taking different values for peak and off-peak periods.

54 The assumption is that available LCE would be pooled across the country and a single value of *k* would be used nationwide. An alternative would be to ring-fence LCE within each island or region of the country to fund LRAs within that island or region – in which *k* would be island- or region-specific.

offers, demand or other market inputs. Results have been published,[55] but are not reproduced here.

E.6 Key messages from the modelling work are that:

(a) the LRA would have relatively little effect on purchase prices most of the time

(b) the LRA would have little effect on long-term average prices at most nodes

(c) the LRA would have a significant impact on purchasers exposed to WIBR:

(i) greatly reducing WIBR in the lower North Island, and at nodes vulnerable to spring washer and pivotal pricing

(ii) somewhat reducing WIBR in most of the rest of the country

(iii) slightly increasing WIBR at some nodes in the upper North Island – though not to a material level, compared to e.g. quantity risk or overall basis risk.

Defining the quantity of energy purchased

E.7 A secondary element of the design is the way in which the "average quantity of energy purchased over some previous time period" would be calculated.

E.8 One possible option would be to use total purchases over the last three calendar months. However, this approach could be adversely affected by seasonal demand fluctuation – e.g. mean demand over February-April may not be an accurate reflection of hedge requirements in May, when residential demand is typically rather higher. It might be preferable to use the average quantity in the last calendar month, or in the same calendar month of the previous year, or over the last 12 months.

E.9 In the long term it would be preferable to measure purchases gross of embedded generation, so as to place embedded and grid-connected generation on a level playing field. However, in the short term, it might be helpful to calculate quantities net of embedded generation as a transitional arrangement, in order to minimise adverse effects on participants that currently use embedded generation to manage WIBR.

E.10 It has been suggested in the past that constrained periods should be excluded from the calculation of quantity – however this approach is no longer favoured as it would add complexity and have little impact on outcomes

55 Appendix H of http://www.ea.govt.nz/dmsdocument/14752

Selection of AMLF

E.11 Another secondary element of the design is the way in which AMLF would be calculated.

E.12 AMLF indicates the averaged marginal loss factor at a particular node. It is preferable to use the averaged (over time) *marginal* loss factor, rather than the averaged (over time) *average* loss factor.

E.13 The suggestion in Sections 3.4 and 0 is that the *AMLF* in the LRA formula should refer to an average (over time) *marginal* loss factor, rather than an average (over time) *average* loss factor, because:

(a) using AMLF is more consistent with electricity market pricing, where marginal prices reflect marginal losses

(b) using AMLF would minimise the effect of the LRA on long-term average nodal purchase prices.

E.14 It is important that the calculation of *AMLF* should not be dynamic. In other words, the value of *AMLF* used for a particular node in a particular month should not reflect conditions in that month. Rather, it should reflect long-term average conditions.

E.15 In principle, a participation factor approach could be used to distinguish the effect of losses from that of constraints. In practice, providing constraints do not bind too often, it may be appropriate to:

(a) calculate *AMLF(n,n')* as the average of *Pr(n) / Pr(n')* over some long period (preferably several years), omitting trading periods where the relevant prices are affected by transmission constraints

(b) update the value of *AMLF* occasionally (not more than annually).

E.16 The above calculation returns values such as:

(a) AMLF(Kensington, OTA) = 1.045

(b) AMLF(New Plymouth, OTA) = 0.96

(c) AMLF(Blenheim, BEN) = 1.11.

A three-node hybrid design

E.17 This section briefly describes how the LRA part of the three-node hybrid option described in Section 3.6 could be designed.

E.18 In many respects, the design could be the same as for the two-node hybrid described earlier in this Appendix. Only the payout formula would need to change.

E.19 For nodes in the North Island, the term *AMLF(n,Ref(n)) x Pr(Ref(n),m)* would be replaced by:

wt(n) x AMLF(n,OTA) x Pr(OTA,m) + (1 – wt(n)) x AMLF(n,HAY) x Pr(HAY,m)

where *wt(n)* would be a weight that varies linearly with latitude, is 1 for nodes *n* at or north of OTA, and is 0 for nodes at or south of HAY.[56] For instance, *wt(WKM)* would be 0.65.

E.20 Again, this LRA scheme has been modelled and applied to calculate what LRA payouts would have been in the 2010, 2011 and 2012 years.[57]

E.21 The key result is that the LRA part of the three-node hybrid should provide purchasers with better cover than the two-node hybrid, providing they are able to use other means (such as the new FTRs, or energy hedges) to manage their price risk between HAY and OTA.

E.22 Following LPRTG feedback, the Authority notes that a key disadvantage of this option would be its increased complexity (relative to the two-node hybrid).

Corner cases

E.23 Experiments show that the LRAs described in this Appendix could result in substantial changes in purchase costs at some nodes in some years, because:

(a) the node was new during the year

(b) the node ceased during the year

(c) the nature of demand at the node changed substantially during the year; or

(d) demand at the node was very low and variable. (For instance, the node was usually associated with generation, but occasionally drew from the grid.)

E.24 It should be possible to use some form of ‘dispensations’ to deal with these kinds of issues (e.g. using estimated demand for new nodes during their first month).

[56] Alternatively, the “spine and ribs” approach could be used. In this case, the weights assigned to OTA and HAY would depend on the latitude of the point where the node connects to the grid backbone (so weights for the Hawkes Bay area would be calculated based on the latitude of the Wairakei node). Or weights could be based on a linear regression of nodal prices against OTA and HAY prices.

[57] Appendix H of http://www.ea.govt.nz/dmsdocument/14752

Appendix F Evaluation of the four high level options against the statutory objective criteria

Table 11: Criterion 1 – Simple and understandable to traders

Option	Evaluation	Rating
Status quo	No additional learning required.	✓✓✓
Two-node hybrid	The proposed LRA has been designed specifically with simplicity in mind. It is a passive product, with no auction or other trading activity required. It would not be expected to increase the complexity of the market significantly.	✓✓
Three-node FTR	Adding a single additional FTR node or hub would not be expected to increase the complexity of the market significantly.	✓✓
Three-node hybrid	The gradation of the North Island LRA from HAY to OTA, and the interaction with FTRs between HAY and OTA, could potentially be confusing.	✓
Multi-point FTR	Adding additional FTR points would permit more complex FTR strategies, and would increase the volume of information generated by FTR auction and settlement processes. The level of complexity would depend to a large extent on the number of new FTR products.	✓✓(for moderate numbers of new FTR points)

Table 12: Criterion 2 – Assists participants to manage WIBR in the LNI

Option	Evaluation	Rating
Status quo	It may be difficult for participants to manage LPR in the LNI using products at OTA and BEN only.	X
Two-node hybrid	Adding a NI LRA would help LNI purchasers to manage the risk. It would, however, be of no use to generators (in their capacity as generators) since they would not be included in the LRA. Integrated generator-retailers might be better or worse off, depending on their individual circumstances.	Load: ✓✓ Generation: X
Three-node FTR	Adding an FTR node at HAY would help participants to manage the risk, although some within-region price risk would remain.	✓
Three-node hybrid	Both the FTR and LRA elements would help participants to manage the risk.	Load: ✓✓ Generation: ✓
Multi-point FTR	Adding an FTR node at HAY would help participants to manage the risk. Any additional FTR nodes in the central or lower North Island would improve the situation further.	✓✓

Table 13: Criterion 3 – Assists participants to manage local spikes in various parts of the grid

Option	Evaluation	Rating
Status quo	It has been demonstrated that price spikes can cause high levels of WIBR in some local areas.	X
Two-node hybrid	Adding LRAs would largely mitigate the risk of WIBR associated with local spikes, for a purchaser.	✓✓✓
Three-node FTR	Adding a single FTR node or hub in the LNI would help participants to manage WIBR associated with price spikes in the LNI, but otherwise would be of little help.	✓
Three-node hybrid	As per “Two-node hybrid” above.	✓✓✓
Multi-point FTR	Coverage would be somewhat ‘hit and miss’. Each additional FTR point would help participants to manage WIBR associated with price spikes *affecting that point*, but otherwise would be of little assistance.	✓✓

Table 14: Criterion 4 – Tradable

Option	Evaluation	Rating
Status quo	Participants can purchase FTRs to suit their individual requirements, and can continue to trade FTRs, either through secondary trading or through reconfiguration auctions once these become available.	✓
Two-node hybrid	As above, participants can trade inter-island FTRs. However, as proposed, the LRA would be obligatory and would not be tradable.[58] If a participant found that the LRA did not assist them to manage WIBR, they could not opt out or otherwise change their LRA “holdings”.	✓
Three-node FTR	Participants could purchase FTRs to suit their individual requirements, and could continue to trade FTRs, either through secondary trading or through reconfiguration auctions once these became available.	✓✓
Three-node hybrid	The FTR element would be tradable, but the LRA element would not.	✓
Multi-point FTR	Participants could purchase FTRs to suit their individual requirements. Secondary trading might be impractical for such a large number of products, but participants could trade FTRs through reconfiguration auctions.	✓✓

[58] Participants could trade their LRA returns on an over-the-counter basis – however a proper exchange-traded product would seem more satisfactory.

Table 15: Criterion 5 – Flexible

Option	Evaluation	Rating
Status quo	Options are currently open to increase the number of FTR points, or to implement LRAs or some other measure.	✓✓
Two-node hybrid	It might be difficult to add more FTR points at a later date, as this would mean removing some of the funding underpinning the LRAs. One factor that could help to compensate for this lack of “evolvability” is that the LRAs in each island would be sufficient to provide pure purchasers with reasonably comprehensive cover, without any further modification.	✓
Three-node FTR	It would be possible at a later stage to create more FTR points and/or implement LRAs or zonal pricing.	✓✓
Three-node hybrid	As per “Two-node hybrid” above.	✓
Multi-point FTR	As the range of available FTR products increased, participants would become better able to arrange comprehensive cover to manage existing and potential risks. It would be possible at a later stage to create more FTR points and/or implement LRAs or zonal pricing.	✓✓

Table 16: Criterion 6 – New-entrant friendly

Option	Evaluation	Rating
Status quo	The status quo exposes new entrant purchasers to potentially high levels of WIBR.	X
Two-node hybrid	This option should help new entrant purchasers to manage WIBR, with little increase in complexity. If the quantities to be used in calculating payouts were to be based on historical demand, then some arrangements would need to be made to estimate the quantity assigned to a new entrant.	✓✓
Three-node FTR	This option should help new entrants to manage WIBR in the LNI, with little increase in complexity.	✓✓
Three-node hybrid	This option combines the advantages of the *two-node hybrid* and *three-node FTR*, but is more complex than either.	✓✓
Multi-point FTR	This option would potentially provide the most assistance to new entrants. It would also increase the level of complexity, but still within reasonable bounds (providing the number of new FTR products was not excessive).	✓✓

F.1 From a new entrant perspective, one potential disadvantage of FTR-based approaches relates to prudential security requirements. Participants must be able to cover the initial margin set out by the Clearing Manager before acquiring FTRs. Meeting this requirement will impose a cost.

F.2 However:

(a) a new entrant could benefit from new FTRs without actually purchasing the FTR (and providing prudential) themselves – in that the availability of FTRs could widen the pool of parties willing to offer hedge at the new entrant's location

(b) two-sided LRAs could also lead to an increase in prudential requirements (since they would impose an obligation on participants to pay out under some circumstances).

Table 17: Criterion 7 – Can be implemented soon

Option	Evaluation	Rating
Two-node hybrid	Further development of LRAs, and amendments to the Code, would be required. A transition period might also be advisable, in order to allow participants to unwind their current arrangements.	✓
Three-node FTR	The FTR manager advises that new FTRs could be available by mid-2014.	✓✓
Three-node hybrid	LRAs as per “Two-node hybrid” above. FTRs as per “Three-node FTR” above.	LRAs: ✓ FTRs: ✓✓
Multi-point FTR	The FTR manager advises that new FTRs could be available by mid-2014.	✓✓

Appendix G Well-designed LRAs need not distort efficient short-term price signals

G.1 It can be shown that an LRA in which the payout in a given trading period was based on quantity during that trading period would distort locational price signals on load. This paper does not propose such an LRA.

G.2 This Appendix shows that an LRA in which the payout in a given trading period is based on *average quantity over an earlier time period* does not distort efficient short-term price signals on load.

G.3 The discussion assumes an LRA similar to that described in Section 3.4, with payout based on the purchaser's mean quantity in the previous quarter.

G.4 Consider a 10 MW load, owned by a consumer called C, at a North Island node called XYZ. The load is normally flat, but can be reduced in response to price signals. We assume (again for simplicity) that C has no other load or generation, and no relevant hedges or other contractual arrangements.

G.5 We divide time into three quarters – Q1, Q2, and Q3.[59] We will consider the impact on price signals in a trading period T in Q2.

G.6 Without the LRA, the net marginal benefit of reducing load would be

P(XYZ) – SRMC, where:

P(XYZ) is the nodal price at XYZ during trading period T

SRMC is the short-term marginal cost of reducing load.

G.7 The payout to C for trading period T is:[60]

MQ(Q1) x [P(XYZ) – P(OTA) x AMLF(XYZ,OTA) x k] x 0.5

where:

MQ(Q1) is the mean quantity consumed by the load during Q1, which is just under 10 MW

P(OTA) and P(XYZ) are nodal prices at OTA and XYZ during T

AMLF(XYZ,OTA) is the average loss factor between XYZ and OTA (Appendix E describes how this might be calculated)

[59] This approach is based on the simplifying assumption that LRA payouts in quarter N are based on average quantities in quarter N-1. In practice, a rolling average quantity might be used (as in Appendix E). The key results in this Appendix hold either way.

[60] It can be shown that this individual-trading-period payout formula produces the same results as the monthly payout formula in the strawman design in Appendix E.

k is a scalar to provide revenue adequacy (exploratory analysis indicates that this would be close to 1 in most months, so it is ignorable for the purposes of this Appendix).

G.8 This payout does not include any terms relating to the quantity consumed by the load during the current trading period T. Therefore, receiving the payout has no effect on the net marginal benefit of reducing load – which remains equal to P(XYZ) – SRMC. <u>The LRA is not distortionary in this regard.</u>

G.9 The LRA can, however, affect incentives in other ways.

G.10 One way in which the LRA can affect incentives is that <u>consumption decisions in one quarter affect the level of payouts in the next</u>.

G.11 A 1 MW increase in consumption in trading period T:

(a) increases MQ(Q2) by (1/N) MW, where N is the number of trading periods in the quarter (about 4400; we will assume for the sake of convenience that all quarters have the same number of trading periods)

(b) increases the payout in each trading period of Q3 by (1/N) x [P(XYZ) – P(OTA) x AMLF(XYZ,OTA)] x 0.5

(c) increases the expected total payout in Q3 by [E(P(XYZ)) – E(P(OTA)) x AMLF(XYZ,OTA)] x 0.5, where:

E(P(XYZ)) is the expected mean price at XYZ during Q3

E(P(OTA)) is the expected mean price at OTA during Q3.

G.12 If E(P(XYZ)) = E(P(OTA)) x AMLF(XYZ,OTA), then there is no effect on the expected total payout in Q3, and there is no distortion to consumption decisions in Q2.

G.13 If C has reason to believe that E(P(XYZ)) differs substantially from E(P(OTA)) x AMLF(XYZ,OTA), then there is distortion to consumption decisions in Q2. In particular:

(a) if C believes that E(P(XYZ)) substantially exceeds E(P(OTA)) x AMLF(XYZ,OTA) – i.e. that local prices will be higher during Q3 than the OTA price plus averaged marginal losses – then C has an inefficient incentive to increase consumption during Q2, in order to increase the LRA payments it will receive during Q3.

(b) if C believes that E(P(XYZ)) is substantially less than E(P(OTA)) x AMLF(XYZ,OTA) – i.e. that local prices will be higher during Q3 than the OTA price plus averaged marginal losses – then C has an inefficient incentive to reduce consumption during Q2, in order to reduce the amount it will have to pay out on the LRA during Q3.

G.14 The Authority takes the provisional view that it would generally be difficult for parties to obtain such knowledge in advance.[61]

G.15 However, following LPRTG feedback, the Authority acknowledges that some stakeholders take a different view. These stakeholders consider that some parties would be able to take a view on the likely sign of E(P(XYZ)) - E(P(OTA)) x AMLF(XYZ,OTA), and therefore that substantial distortion *would* result.

G.16 Another way in which the LRA can affect incentives is by <u>changing the benefit that C can derive from influencing the local price downwards</u>.[62]

G.17 Consider the situation when XYZ is separated from OTA by a transmission constraint, and C knows it can influence the price at XYZ by changing its consumption decisions.

G.18 Suppose that, by reducing load from 10 MW to 5 MW, C is able to change the nodal price from P(XYZ) to a lower number P'(XYZ), without affecting the price at OTA.

G.19 If there was no LRA, then the reduction in C's purchase costs would be equal to:

[10 P(XYZ) – 5 P'(XYZ)] x 0.5

= [5 P'(XYZ)] x 0.5 + [10 x (P(XYZ) – P'(XYZ))] x 0.5

G.20 With the LRA, the reduction in C's purchase costs would be equal to:

[10 P(XYZ) – 5 P'(XYZ)] x 0.5 – [MQ(Q1) x (P(XYZ) – P'(XYZ))] x 0.5

= [(10 – MQ(Q1)) x P(XYZ) + (MQ(Q1) – 5) x P'(XYZ)] x 0.5

≈ [5 P'(XYZ)] x 0.5 *(assuming MQ(Q1) ≈ 10 MW).*

This is identical to the first term at G.19 above – which reflects the benefit of reducing quantity – but does not include the second term at G.19 above – which reflects the benefit of reducing price.

G.21 In other words, the LRA removes C's ability to derive benefit from influencing the price downwards in a constrained region. However, it is not clear that it would have been efficient for C to influence prices in this way in the first place.

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[61] There might be occasional exceptions. For instance, C might anticipate that E(P(XYZ)) would be unusually high in Q3 if a transmission outage was planned and there was the potential for a locally pivotal supplier to influence P(XYZ) upwards. This would create an inefficient incentive for C to increase load in Q2. However, the incentive would be fairly dilute, and most consumers would not find it economic to increase load *above* their normal level for an extended period (or be able to justify doing so on the basis of speculations about future electricity prices).

[62] As opposed to the effect on the benefit that a generator-retailer can gain by influencing the local price *upwards* – this is a separate but related issue and is dealt with in Appendix D.

Appendix H The incremental benefit of adding more FTR points

H.1 This Appendix describes statistical analysis carried out to assess where new FTR points should be added, and the incremental benefit of adding each point.

H.2 The analysis:

(a) defines a measure of the “residual risk” for a given set of FTR points. This measure assesses the amount of historical price risk that could not have been managed using those FTR points

(b) begins with FTR points at OTA, BEN and HAY and iteratively finds the new FTR point that would most reduce the “residual risk” measure

(c) shows the reduction in “residual risk” at each step.

H.3 For a given set of FTR points *FP*, the residual risk measure *RRisk(FP)* is defined as:

$$RRisk(FP) = \frac{\sum_{\text{pricing nodes } n} \text{std. dev}\left(P_{n,m} - \text{Hedge}_{n,m,FP}\right) \times (L_n + G_n)}{\sum_{\text{pricing nodes } n} (L_n + G_n)}$$

where:

(a) *std. dev* is the standard deviation of months in the analysis period (Jan 2001 to Sep 2012 inclusive)

(b) $P_{n,m}$ is the mean price (TWAP,[63] $/MWh) at node *n* in month *m*

(c) $Hedge_{n,m,FP}$ is a linear combination of mean prices (TWAP, $/MWh) in month *m*, at no more than two FTR points. The two FTR points are chosen from the full list in *FP*, and the coefficients of the linear combination are selected (using a regression model), so as to minimise the deviations between $P_{n,m}$ and $Hedge_{n,m,FP}$ over the 12-year analysis period[64]

(d) L_n is long-term average load (GWh/month) at node *n*

(e) G_n is long-term average grid-connected generation (GWh/month) at node *n*.

H.4 In the above formula, $P_{n,m} – Hedge_{n,m,FP}$ represents deviations between actual prices at *n* and a hedge that could be constructed using energy hedges at OTA and BEN and FTRs between the available FTR points.

[64] For instance, the model chooses to hedge Linton as 0.71 x Haywards + 0.29 x Wairakei

[64] For instance, the model chooses to hedge Linton as 0.71 x Haywards + 0.29 x Wairakei

H.5 If a node *n* is close (in price terms) to at least one of the FTR points in *FP*, then it could be well hedged, and this deviation is small for most or all months.

H.6 A node *n* makes a substantial contribution to *RRisk* if:

(a) it has substantial load and/or substantial grid-connected generation

(b) it is subject to LPR; and

(c) it is not close (in price terms) to any of the FTR points in *FP*.

H.7 *RRisk* is large if there are few nodes in *FP*, but decreases as each new node is added to *FP.* The decrease is greatest if the new node is close (in price terms) to one or more nodes that:

(a) has substantial load and/or substantial grid-connected generation

(b) is subject to a material level of LPR.

H.8 If *FP* included all pricing nodes in the grid, then *RRisk* would be zero.

H.9 The inter-island FTR will cover OTA and BEN; the Authority's analysis[65] suggests that another node should be added at (or near) HAY. The value of *RRisk* is relatively high for *FP = {OTA, BEN, HAY}*, but decreases as more nodes are added (Figure 15 – or may be clearer in Figure 16).

[65] Within-island basis risk: quantifying the risk, available from http://www.ea.govt.nz/our-work/advisory-working-groups/lprtg/14feb13/

Figure 15 Reduction in residual risk as more FTR nodes are added

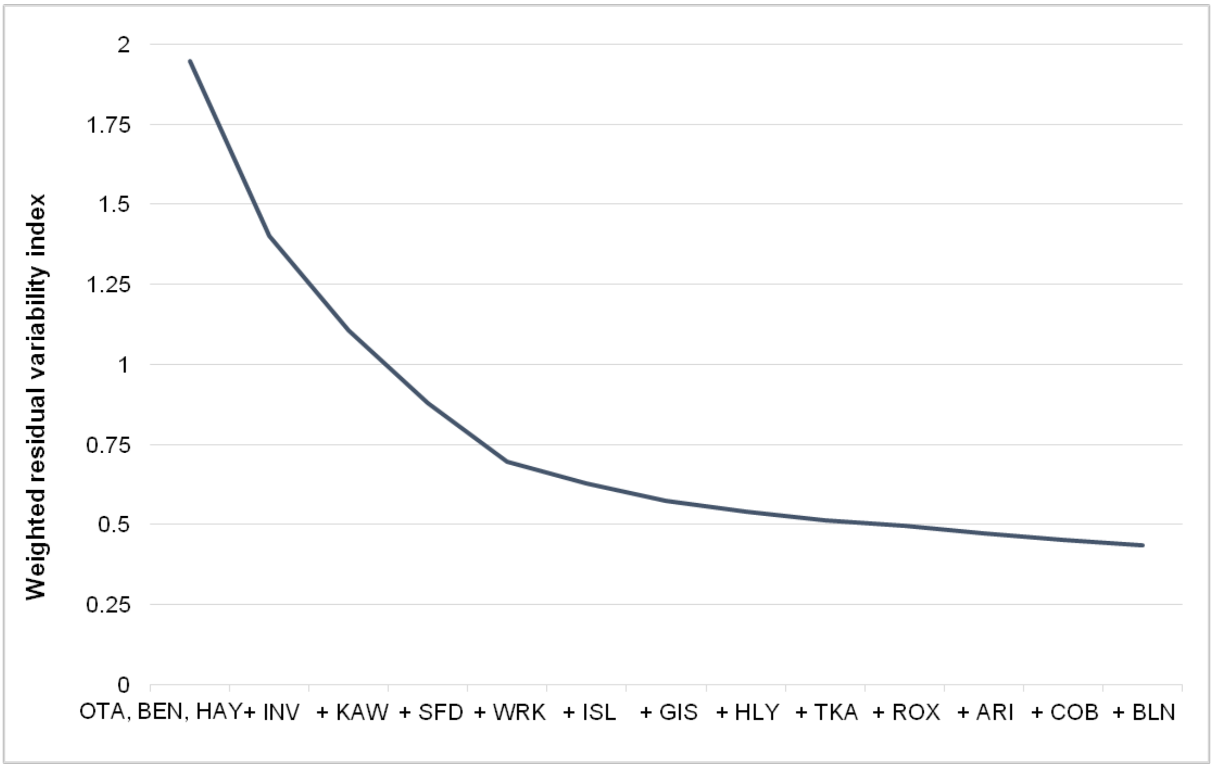
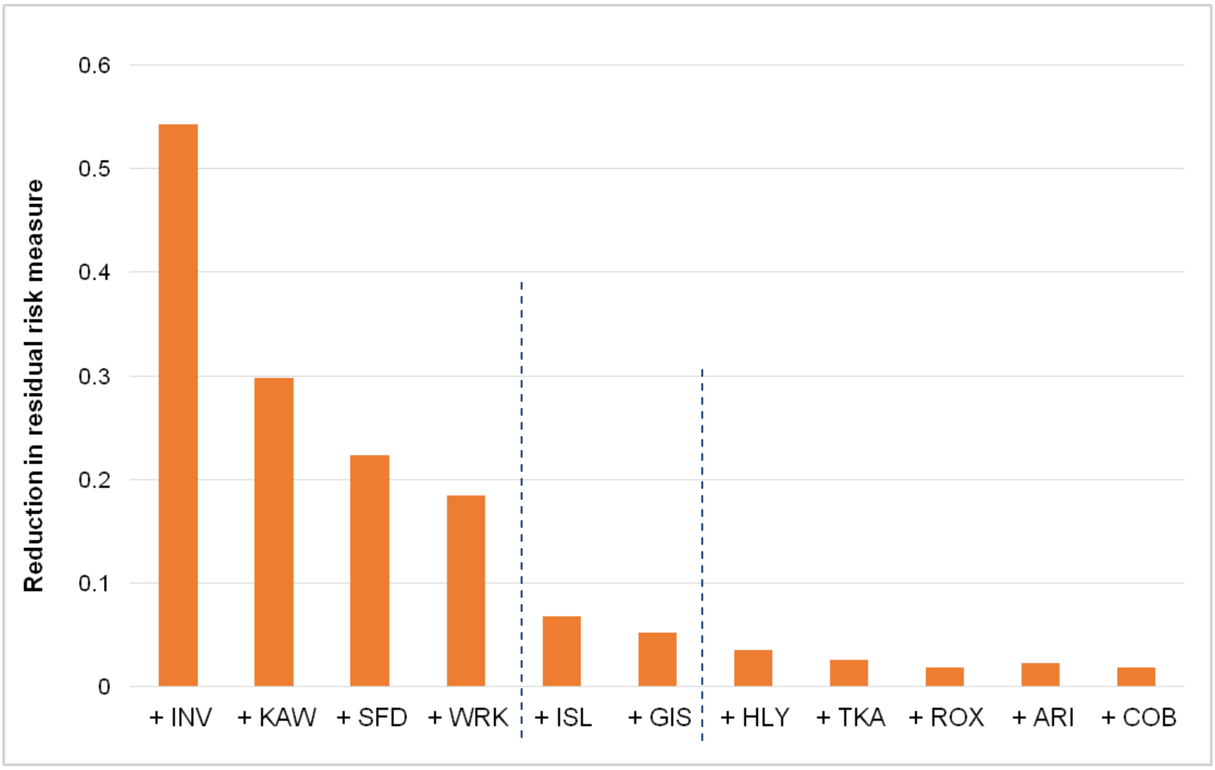


Figure 16 Value added by each additional FTR point, over and above OTA, BEN and HAY



H.10 With *FP = {OTA, BEN, HAY},* the single node that most decreases *RRisk* is Invercargill (INV), providing hedge cover to the lower South Island. (The benefit may be overstated as it is heavily influenced by the large load at Tiwai and large injection at Manapouri.)

H.11 With *FP = {OTA, BEN, HAY, INV}*, the next node that most decreases *RRisk* is Kawerau (KAW, providing hedge cover to the Bay of Plenty), then Stratford (SFD, covering Taranaki) and Wairakei (WRK, covering the central North Island).

H.12 At this point returns are diminishing steeply, but there is moderate incremental benefit from adding Islington (ISL, covering the upper South Island) and Gisborne (GIS, covering the East Cape region).

H.13 Beyond this point there is relatively little incremental benefit. However, *RRisk* can still be reduced by adding nodes such as Huntly and Roxburgh (HLY and ROX, close to major injection points), Tekapo A and Cobb (TKA and COB, susceptible to pivotal supplier situations), and Arapuni, Blenheim and Hamilton (ARI, BLN and HAM) where there is also some residual risk.

H.14 A limitation of the analysis is that it is based on historical prices. In fact, the future may differ from the past. The analysis *could* be extended to include sensitivities. However, this would accord the analysis more importance than it may deserve – given that it is only one input into the process of deciding where any new FTR points may be located. (Stakeholder feedback would be a more important input.)

H.15 Another limitation of the analysis is that it assumes perfect foresight in making hedge arrangements. In reality, locational price risks cannot always be foreseen on hedging timeframes. The analysis probably therefore underestimates the level of residual risk that would occur in practice.