TRANSPOWER NEW ZEALAND LIMITED

Submission to the Electricity Commission on Managing Locational Price Risk: Options

7 December 2009

TRANSPOWER

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1. Introduction

1.1 Purpose of this document

Transpower thanks the Electricity Commission for the opportunity to submit on its consultation document "Managing Locational Price Risk: Options", October 2009. This report is Transpower's response to the consultation document.

This submission should be read in conjunction with Transpower's Submission to the Electricity Commission on Market Development Program: Overview, December 2009.

2. Executive summary

The Commission is embarking on an important market development programme that requires careful coordination of all elements to deliver good consumption, investment and divestment signals, liquid hedge and contract markets, increased competition and reduced barriers to entry for new retailers.

Within the context of integrated market development, Table 1 summarises how, in our view, each of the options in the discussion paper are measured against the criteria set for locational price risk management:

Option	Objectives met?	Comment
Option 1: Locational Regional Allocation (LRA)	✗	The LRA does not assist with competition because it does not enable a hedge against locational price risk that can be aligned with an energy contract.
Option 2: Financial Transmission Rights (FTRs)	✔	FTRs can be designed to align with energy contracts to provide the holder of the FTR with a revenue stream equivalent to their locational price risk. In this way FTRs have the potential to enhance competition.
Option 3: Hybrid LRA/FTR	✗	The option does not assist with competition because it does not enable a full hedge against locational price risk that can be aligned with an energy contract.
Option 4: Zonal pricing	✗	Provides no locational price risk management options between zones.

Table 1: Summary of proposed options as measured against objectives.

Three of the proposed options (1, 3, & 4) have the effect of changing the price for energy purchasers in the wholesale market by introducing a form of zonal pricing.

We are of the view that this is undesirable because:

- zonal pricing should be considered within the broader context of market development (for example, the way in which it might interact with the objectives of scarcity pricing);
- zonal pricing, in particular LRAs, do not deliver an adequate hedge for incumbents, or new entrants, who want a locational hedge to balance an energy hedge/contract. LRAs would therefore be of little assistance to increasing competition in the electricity market.
- the consultation paper has not adequately identified or quantified the benefits of the zonal pricing options relative to the economic cost of (for example) muting economic signals; and
- zonal pricing will create value transfers that may not be accommodated within existing commercial arrangements and is not justified, in the consultation paper, relative to any potential benefits.

For the reasons summarised in Table 1, and expanded above, it is our view that the locational price risk management option that is most consistent with the market development objectives is the Commission's Option 2 – FTRs.

Option 2 – FTRs is the only proposed option that has been tried and tested in other jurisdictions and could be introduced in a phased and managed way that allows for a careful transition to a new commercial framework.

Critically, Option 2 preserves options for adaptation of the FTR design, over time, to align with all other market developments such as a contract energy hedge market, scarcity pricing and the review of the transmission pricing methodology.

In our advice[1] (on FTR options) to the Commission we outlined the FTR design parameters and how they could be considered to achieve policy objectives. Our advice seeks to address learnings, from the 2001 attempt to introduce FTRs, by proposing a significantly simpler design and the use of hub-only trading to mitigate market concerns raised at the time.

We intended for our advice to be a starting point for a discussion, on significant issues, with affected parties. Our view is that FTRs (or any other locational price risk tool) are an important tool for managing commercial risk and facilitating greater efficiency of the electricity market. The final form of any tool is therefore best designed in a partnership between the industry and regulator.

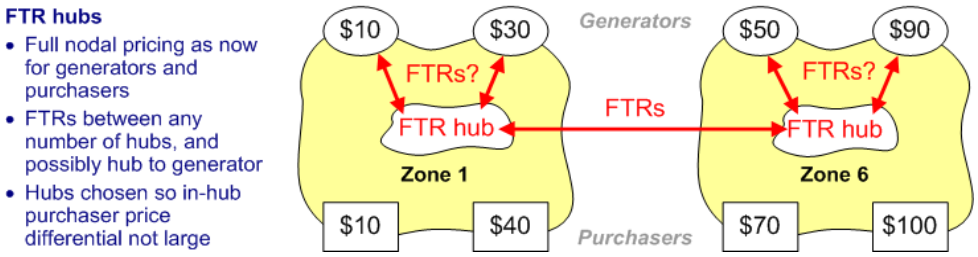
[1] Appendix 3 to consultation document "Managing locational price risk: Options" October 2009

The consultation document has rightly questioned some of our proposed initial settings and recommended others. In our view, the details of design should be carefully worked through with the affected parties.

We therefore **recommend** that the Commission consider:

1. Adopting a high level process with the following principles:
   - phasing that provides options for development of hedging instruments over the long-term rather than making a single, major, change that locks in value transfers and limits future options;
   - consistency between all market development initiatives to ensure that locational price risk management works in concert with energy hedges/contracts to deliver full price certainty; and
   - alignment with international best practice in locational price risk management.

2. Consistent with the principles outlined in recommendation 1, initiate a process to implement Option 2 – FTRs, as a simplified mandatory hub-to-hub model, conceptually illustrated below:



with the following high level design considerations:

- an acceptable number of appropriately selected but mandated FTR trading hubs to be used for FTR trading not purchaser pricing, with hubs being chosen so that the in-hub purchaser price differential is not large;
- an allocation of residual constraint rentals and FTR auction income in a manner that is efficient and agreed by the industry;
- the ability, over time, for the market participants to reconfigure their energy contracts and FTRs to fully manage risk relative to the FTR hubs;
- if further encouragement of retail competition is found, over time, to be required, then consider evolving the FTR design or implementing a well considered alternative; and
- review of the FTR design parameters.

3. Abandoning the LRA concept in both its national or hybrid form, as we believe that it would entrench incumbencies, not promote competition.

3. Defining the problem

3.1 The objective

The consultation paper has the stated objective to introduce a risk management instrument that:

- enables participants to manage basis price risk caused by transmission constraints;
- assists with competition in the wholesale market; and
- reduces barriers to retail entry, such as vertical integration and regionalisation of generation and retail.

We agree with these objectives and suggest they could be enhanced by adding the following:

- ability to evolve and align with developments in the energy hedge/contract market and with other market developments such as scarcity pricing;
- minimal disruption to existing commercial framework by avoiding unnecessary value transfers and distortion to marginal production and consumption signals; and
- simplicity, transparency and predictability. The predictability should not necessarily be in price itself, as it is a market, but in the performance of hedging instruments.

3.2 The problem

In nodal spot markets volatility can be high and can occur with short notice. Market participants will seek to reduce price risk by smoothing short term volatility by using, in part, long term energy supply contracts.

When a market participant has an energy supply contract with delivery at one point and payment at another they can also be subject to transmission locational price risk[2] (or basis risk). In national aggregate, this price risk is exactly equivalent to the rentals generated between the trading points in the network.

An energy supply contract therefore only creates certainty of energy supply price at the reference node for the contract, not locational price

[2] Constraints in the transmission network may result in the dispatch of more expensive generation and hence create price separation, exposing a market participant with a contract for injection at one point and payment at another, to additional cost. The additional cost is the incremental cost of dispatching the next most expensive generator to meet the contracted supply, and is caused by transmission constraints.

differences (or basis risk) between the reference node and other nodes arising from transmission constraints.

To fully hedge themselves market participants require both:

- an energy supply contract to a specified location, capacity and time period; AND
- a transmission constraint hedge (funded by the rentals) between the contractual reference node and participant's injection or offtake node for the same capacity and time period as the energy supply contract.

Properly structured energy contracts complimented by transmission constraint hedges are important elements that help to facilitate a thriving, **liquid and competitive** electricity market.

The problem is that New Zealand has never implemented a transmission constraint hedge to manage locational price risk <u>in conjunction with energy contracts.</u>

The failure to properly deal with locational price risk has lead to significant investment in vertical integration and regionalisation of retail and generation to minimise commercial risk. It is assumed that this has created barriers to the entry of independent retailers and has limited competition in the New Zealand electricity market.

Further, EnergyHedge and other futures markets cannot address the underlying issue of basis risk: Without a rentals-funded locational price risk management tool, someone has to take that risk.

The solution should therefore be to use the rentals to exploit the direct relationship between rentals and locational price risk.

3.3 The solution

The consultation paper has proposed four technical options to address the problem and achieve the objective.

The suggested solution options are:

1. Locational Rental Allocations (LRAs) – an LRA allocates constraint and, possibly, loss rentals to a spot market purchasers in proportion to their locational price risk using a formula;
2. Financial Transmission Rights (FTRs) – an FTR auctioned and provides the holder with the right to the constraint rentals between the points specified by the FTR;
3. a hybrid of LRAs and FTRs – rentals are allocated in some regions using LRAs with FTRs between regions; and

4. zonal[3] pricing – load (and possibly generation) at all nodes within a zone are subject to the same price.

The consultation paper indicates option 3 (a hybrid of LRAs and FTRs) as preferred. We note the Commission's statements that this preference over other options is weak, in that the cost-benefit analysis is not conclusive.

The only option that adequately deals with the problem as outlined in section 3.2 is Option 2 – FTRs in the discussion document.

3.4 Scope of consultation

Three of the four options in the consultation document implement, in effect, some form of zonal pricing. Of course there are pros and cons of aggregated purchase pricing but the pros have, at least, to be balanced against the cons.

The consultation does not adequately quantify the national net economic benefits of any of its proposed options relative to the desired policy outcomes.

In the absence of this, and given how close and overlapping the cost benefit results were in any case, we do not believe that that the cost-benefit analysis in the consultation paper provides any robust basis for preferring one option over another.

As explained in this submission, we believe that only one of the options are likely to achieve the desired policy outcomes, so the test should be whether that FTR option is better than doing nothing.

Given that the cost is a primarily a one-off few million dollars, but the benefits relate to significant improvements in the levels of competition in a $7 billion per annum market, we do not believe that demonstrating net benefit will be problematic.

[3] Here we use the term zone to mean a contiguous geographic area containing grid injections and exit (offtake) points, and the term hub to mean a purchase price in a zone, calculated typically as a weighted average of injection and/or offtake prices.

4. Analysis of proposed solutions

The commentary and observations outlined in this section are derived from Transpower's modelling of the LRA formulation provided in the consultation document. Transpower's 2, 3 and 7 node models can be found at www.transpower.co.nz/ftr.

Transpower would welcome any further discussion on its models.

4.1 Option 1: Locational Rental Allocation

What is a Locational Rental Allocation?

Figure 1 represents a conceptual illustration[4] of a single national floating generator hub using LRA payments to set a single purchaser price based on a weighted average generator price (G-hub price).

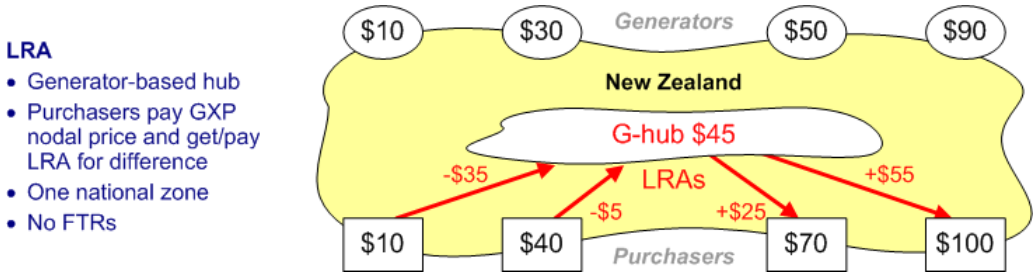


Figure 1: One floating national generator hub using LRA payments to set a single purchaser price based on a weighted average generator price (G-hub price).

With basic, fully allocated, LRAs applied to all purchasers:

- purchasers pay nodal price for full quantity of offtake;
- LRAs (red arrows) recompense the difference between the nodal price and a hub price (supply weighted average price – G-hub in the figure), for a quantity based on historical purchases;
- all the constraint rentals are used to fund the LRAs.

[4] This and subsequent like-diagrams assume for simplicity of illustration and ease of arithmetic no losses and each of the four generators and purchasers injecting and demanding the same MW quantity.

This is arithmetically equivalent to:

- compulsory purchase of X MW at the G-hub price, where X is the result of a regulated formula based on historical purchases; and
- a balancing market for any overs and unders (in actual quantity of offtake relative to historical quantity) at the nodal price.

Expressed this way, it can be more clearly seen that LRAs would create a significant change to current commercial arrangements in the industry.

General observations

- Strictly speaking, LRAs are an allocation not a hedge as they are allocated, not traded (or meaningfully tradable);
- LRAs can be a payment (-ve) or a receipt (+ve);
- LRAs only provide a partial "hedge",
  - because all rentals are used for the LRA, none remain for generators to hedge between injection nodes and the G-hub (ISWAP);
  - that is, purchasers are "hedged" against basis risk relative to a floating hub[5] (G-hub/ISWAP), but generators cannot hedge against their basis risk relative to that floating hub (refer to Figure **1**);
- LRAs are likely to provide limited assistance to competition as they do not allow basis risk to be managed relative to an energy contract (generators will not be able to get an LRA from their point of generation to their point of sale – the G-Hub, and purchasers will not be able to get an LRA from the G-Hub to their point of purchase if it is not the G-Hub);
- LRAs cause value transfers because:
  - LRA payments are dependent on how historical offtake is measured[6];
  - LRAs change the price paid by purchasers from the nodal spot price to the generation weighted average price for the zone[7]; and

[5] As long as their purchase price is the G-Hub price. If their purchase price is any other location (node) the LRA will only provide a "hedge" to the G-Hub price, which may be different to their actual purchase price, so they may only receive a partial hedge (because the "hedge" is not aligned with the energy contract).

[6] Deciding on this measurement approach will be a practical issue of value transfer between those with different load profiles, e.g. flat v. peaking, day v. night, summer v. winter, weekday v. weekend etc. (In the case of the preferred hybrid option with HVDC treated as offtake, the measurement of HVDC offtake will be critical too, and problematic as it varies so much in both quantity and direction. It may be necessary to use actual amounts for the HVDC.)

  - LRAs do not accommodate existing commercial arrangements because a significant portion of load in the market will be effectively settled at a price (G-Hub price) different to the price referenced in energy contracts (reference nodal prices).
- the floating G-Hub price will not be known in advance;
- LRAs only work for up to two LRA zones[8]; and
- LRAs cannot be optional since the mechanism effectively creates a single zonal price equivalent to the weighted average generation price. Given the choice, those that benefit will opt in and those that lose will opt out. Mandatory LRAs create only a partial hedge – optional LRAs would be significantly less effective as a hedge.

[7] This will mean that, under an LRA regime, those currently paying nodal prices less than the G-Hub price will be paying more and those with nodal prices greater than the G-Hub price will be paying less.

[8] Option 1 is a single national zone. Option 3 – the hybrid LRA/FTR model, is for two zones with an HVDC interconnect that does not have loop flow. As explained in the discussion paper and in section 4.3 below, this is technically difficult. LRAs with more than two zones would involve multi-circuit AC flows with loop flow potential between zones, and significant offtake/injection imbalance between zones. In Transpower's view such an LRA regime would be intractably complicated.

Do LRAs meet the objectives?

Objectives	Objectives met?	Reason
Basis risk managed	Partial	Does not enable generator to floating G-Hub hedging or floating G-Hub to purchaser node hedging. For large national or island LRA zones, the generation to hub basis risk will be considerable.
Value transfers minimised	✗	Price formula based on historical load profile. G-hub price different to underlying nodal price.
Marginal signals preserved	Partial	LRAs are designed to preserve marginal signals, but as the revised consultation paper now acknowledges "distortion could arise [and the] best overall compromise formula has not been investigated".
Retail competition enhanced	✗	Both incumbent and new entrant retailers will still need to regionalise generation and retail in order to manage basis risk because LRAs do not provide a hedge from the point of generation to the point of sale (the floating G-hub).
Barriers to entry reduced	✗	See point above.
Simple, transparent and predictable outcomes	✗	G-Hub price not known ahead of time.
Can be configured to complement energy contract	✗	Not in the general case as there is a difference between generation price and purchase price which cannot be hedged with this option.

4.2 Option 2: Financial transmission rights

What is an FTR?

FTRs are financial hedges that help protect energy purchasers and sellers from price uncertainty caused by transmission constraints.

FTRs confer the right on the FTR holder to receive the constraint rentals[9]. In this way FTRs can be designed to provide buyers and sellers with the opportunity to accept and offer fixed price contracts at any location. This is conceptually illustrated in Figure 2 below.

FTRs are auctioned.

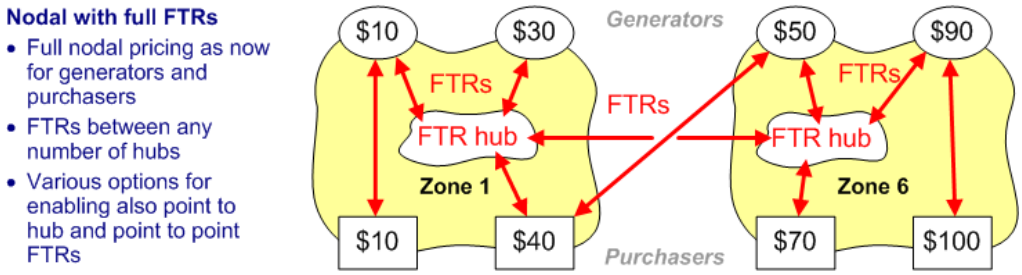


Figure 2: Conceptual illustration of node-to-node FTR design. FTRs can be configured as node-to-node, node-to-hub or simply as hub-to-hub as required.

General observations

The consultation document identifies the main advantages of FTRs, which include:

- FTRs preserve locational signals for both load and generation; and
- FTRs enable participants to actively match their basis risk hedge with their trading patterns.

The consultation document identifies the main disadvantages of FTRs, which include:

- FTR complexity – will not provide a full hedge unless a full nodal FTR regime is implemented;
- FTRs do not provide incentives for purchasers with market power to refrain from using that power; and
- FTRs require active participation by parties to hedge their locational price risk.

[9] The difference between the prices at the nodes (hubs) for which the hedge is written for a defined amount of megawatts and a defined period of time.

We agree that the disadvantages identified are barriers to FTR implementation. However, we also feel that the benefits of FTRs (in relation to the objectives[10] of the consultation) are so substantial in comparison with all the other options proposed in the consultation document that is worth persevering with the design and implementation of simplified FTRs.

Simplified FTRs**,** offered between mandated hubs, can mitigate concerns by:

- Reducing complexity by providing for limited hub-to-hub trading only;
- Increasing competition for FTRs between hubs because there is likely to be more bidders within a hub than at a node; and
- Reducing the potential for an individual bidder to exercise market power in the FTR market within a hub because there are likely to be more bidders within a hub than at a node.

While we acknowledge industry and regulatory concerns about market power abuse, we do not subscribe to the notion that FTRs will, of themselves, increase the market power problem since any incentive to exploit market power already exists in the much larger (by value) energy market.

In some instances the ownership of specific FTRs may increase a participant's incentive to manipulate nodal prices where it can. On the other hand, FTRs will also make any such actions more visible[11]. The cure to this is not to deny the market access to tradeable locational hedges; rather, it is to enhance energy market monitoring, as the Commission is proposing to do (in its parallel scarcity pricing and compulsory contracting work stream).

FTRs remain a standard component of the market design in most overseas electricity markets that, like New Zealand, are based on locational marginal (or nodal) pricing.

Finally, FTRs do not need any opt-out or buy-in provisions as have been proposed for LRAs because participation in the FTR market is entirely voluntary.

[10] Enables participants to manage basis risk caused by transmission constraints. Increase competition in the wholesale market. Reduce barriers to retail entry.

[11] The reason FTRs make market power activities visible is that the party capable of using the FTR to exercise market power in the energy market will pay far more for an FTR than it is worth. An FTR is only worth the market estimate of constraint rentals plus a premium for price certainty.

Do FTRs meet the objectives?

Objectives	Objectives met?	Reason
Basis risk managed	✔	Basis risk is directly related to the rentals generated by transmission constraints. The only known and tested instrument that exploits this relationship is an FTR[12].
Value transfers minimised	✔	Can be implemented with minimal[13] (if any) value transfers.
Marginal signals preserved	✔	Consistent with market design using nodal pricing and preferred means of managing basis risk in other nodal markets.
Retail competition enhanced	✔	Simplified FTRs would enable basis risk management, reducing reliance on vertical integration and regionalisation, opening the way for retail competition[14].
Barriers to entry reduced	✔	FTRs are auctioned so become available to those who value them most.
Simple, transparent and predictable outcomes	✔	Consistent with market design using nodal pricing. Information provision and FTR market design will deliver this criterion if the FTR design is kept simple.
Can be configured to complement energy contract	✔	Energy contracts and FTRs can be exactly matched to provide a full hedge – hence supports retail competition (as long as hubs are small).

[12] FTRs give the right to the receipt of transmission constraint rentals. When an FTR is matched with an energy contract locational price risk is fully hedged.

[13] Value transfers will arise from a change in the mechanism to allocate FTR auction income and residual rentals. If the method currently used to allocate rentals is used to allocate residual rentals and auction income value transfers will be minimised.

[14] Incentives would be such that alignment of new or re-negotiated energy contracts to FTR hubs can be expected to proceed rapidly.

4.3 Option 3: Hybrid LRA/FTR

What is a hybrid FTR/LRA?

The consultation document indicates a weak preference for a system of two LRA zones, one in the North Island and one in the South Island, with an FTR between the two LRA "zones".

Figure 3 below is a conceptual illustration of the hybrid proposal.

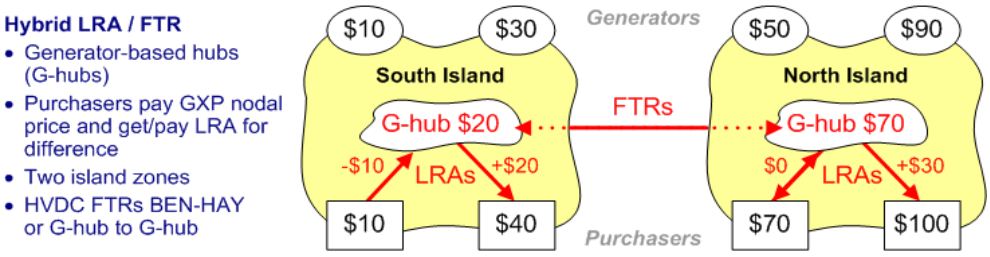


Figure 3: Conceptual illustration of the LRA/FTR hybrid option.

With basic LRAs, fully allocated to all purchasers:

- purchasers pay the nodal price for their full quantity of offtake;
- LRAs (red arrows) recompense purchasers the difference between the nodal price and a hub price (supply weighted average price – G-hub in Figure 3), for a quantity based on historical purchases;
- a G-Hub price is generated for each island for each trading period, and can be expected to become the de facto single purchaser price for the island since purchasers can be expected to factor LRA payments into their commercial positions; and
- all the rentals generated in each island are used to fund the LRAs for that island and the inter-island FTR.

General observations

The same general observations noted in section 4.1 above on LRAs apply.

The differences between this hybrid option and national LRAs (option 1) are the size of the zones (islands not national) and the treatment of inter-island FTRs.

The revised consultation paper, issued by the Commission on 25 November, corrected some anomalies in the previous version. In brief, there are two ways to treat the inter-island link, and neither is satisfactory.

One method is to treat the HVDC as injection to the receiving island and as negative injection in the sending island. This is consistent with the LRA philosophy of injection-weighted island hubs, as for example, the receiving island hub allows for the import of typically cheaper power across the link, thus depressing the hub price. However, this would leave no rentals for an inter-hub FTR, which would have to be a Benmore-Haywards FTR only.

This would be unsatisfactory as participants would obtain partial hedges to their island hubs in the form of hedges between Benmore or Haywards, but not be able to hedge the basis risk between Benmore or Haywards and the island hubs. This would lead to a very disjointed and ineffective hedging regime.

Another method is to treat the HVDC as negative offtake in the receiving island and as offtake in the sending island. This method is the revised consultation paper's stated preference. It provides sufficient LRAs to the HVDC to enable an FTR between the island hubs to be funded. However, it does this only by increasing the generation hub prices. The hub prices may be increased so much that the LRAs to purchasers in each island are net negative; that is, the generator-weighted hub price (which no longer allows for cheap HVDC import) can actually exceed the purchaser-weighted price. Transpower does not believe that the commercial consequences of this will be acceptable.

This issue is explained in greater detail, with examples, in Appendix 1.

Does the hybrid LRA/FTR option meet the objectives?

Objectives	Objectives met?	Reason
Basis risk managed	Partial	Does not enable generator to floating G-Hub hedging. For large national or island LRA zones, the generation to hub basis risk will be considerable.
Value transfers minimised	✗	Price formula based on historical load profile Floating G-hub price different to underlying nodal price
Marginal signals preserved	Partial	LRAs are designed to preserve marginal signals, but as the revised consultation paper now acknowledges "distortion could arise [and the] best overall compromise formula has not been investigated"
Retail competition enhanced	✗	Both incumbent and new entrant retailers will still need to regionalise generation and retail in order to manage basis risk because LRAs do not provide a hedge from the point of generation to the point of sale (the floating G-hub)
Barriers to entry reduced	✗	See point above
Simple, transparent and predictable outcomes	✗	Floating G-Hub price not known ahead of time
Can be configured to complement energy contract	✗	Not in the general case as there is a difference between generation price and purchase price which cannot be hedged with this option.

4.4 Option 4: Zonal pricing

What is Zonal pricing?

Zonal pricing could be implemented by setting prices for load and/or generation to a reference price defined as a zonal reference node, or to a zonal hub price formed by averaging nodal prices.

As zonal pricing without FTRs will only provide a form of locational hedge within zones, but not between them, we do not consider it to be a serious option for managing locational price risk.

Zonal pricing with aligned FTR hubs would be an option, but as it is the FTRs not the zonal pricing that manage practically all the locational price risk, a sensible approach would be to implement FTRs first.

General observations

As a general comment, zonal pricing:

- will mute demand side signals;
- will create value transfers relative to the status quo;
- in and of itself will not provide any inter-zonal locational price hedging;
- would have to be implemented with a hedging mechanism to manage inter-zonal locational price risk; and
- would fundamentally change the economic and commercial framework of the electricity market.

Does the zonal pricing option meet the objectives?

Objectives	Objectives met?	Reason
Basis risk managed	✗	No hedging mechanism between zones and from generator to zone price
Value transfers minimised	✗	Zonal price different to underlying nodal price
Marginal signals preserved	✗	Not in zone. Depending on how many zones there were nationally some marginal signals could be preserved but muted
Retail competition enhanced	✗	Basis risk not hedged so of no assistance to retail competition
Barriers to entry reduced	✗	See above
Simple, transparent and predictable outcomes	✔	Zonal prices can be published as nodal prices are currently published
Can be configured to complement energy contract	✗	No hedging associated with zonal pricing

5. Conclusions

The Commission is embarking on an important market development programme that requires careful coordination of all elements to deliver good consumption, investment and divestment signals, liquid hedge and contract markets, increased competition and reduced barriers to entry for new retailers.

Within the context of integrated market development, Table 2 summarises how, in our view, each of the options in the discussion paper are measured against the criteria set for locational price risk management:

Option	Objectives met?	Comment
Option 1: Locational Regional Allocation (LRA)	✗	The LRA does not assist with competition because it does not enable a hedge against locational price risk that can be aligned with an energy contract.
Option 2: Financial Transmission Rights (FTRs)	✔	FTRs can be designed to align with energy contracts to provide the holder of the FTR with a revenue stream equivalent to their locational price risk. In this way FTRs have the potential to enhance competition.
Option 3: Hybrid LRA/FTR	✗	The option does not assist with competition because it does not enable a full hedge against locational price risk that can be aligned with an energy contract.
Option 4: Zonal pricing	✗	Provides no locational price risk management options between zones.

Table 2: Summary of proposed options as measured against objectives.

Three of the proposed options have the effect of changing the price for energy purchasers in the wholesale market by introducing a form of zonal pricing.

We are of the view that this is undesirable because:

- zonal pricing should be considered within the broader context of market development (for example, the way in which it might interact with the objectives of scarcity pricing);
- zonal pricing, in particular LRAs, do not deliver an adequate hedge for incumbents, or new entrants, who want a locational hedge to balance an energy hedge/contract. LRAs will therefore be of little assistance to increasing competition in the electricity market.
- the consultation paper has not adequately identified or quantified the benefits of the zonal pricing options relative to the economic cost of (for example) muting economic signals; and
- zonal pricing will create value transfers that may not be accommodated within existing commercial arrangements and is not justified, in the consultation paper, relative to any potential benefits.

For the reasons summarised in Table 2, and expanded above, it is our view that the locational price risk management option that is most consistent with the market development objectives is the Commission's Option 2 – FTRs.

Option 2 – FTRs is the only proposed option that has been tried and tested in other jurisdictions and could be introduced in a phased and managed way that allows for a careful transition to a new commercial framework.

Critically, Option 2 preserves options for adaptation of the FTR design, over time, to align with all other market developments such as a contract energy hedge market, scarcity pricing and the review of the transmission pricing methodology.

In our advice[15] (on FTR options) to the Commission we outlined the FTR design parameters and how they could be considered to achieve policy objectives. Our advice seeks to address learnings, from the 2001 attempt to introduce FTRs, by proposing a significantly simpler design and the use of hub-only trading to mitigate market concerns raised at the time.

We intended for our advice to be a starting point for a discussion, on significant issues, with affected parties. Our view is that FTRs (or any other locational price risk tool) are an important tool for managing commercial risk and facilitating greater efficiency of the electricity market. The final form of any tool is therefore best designed in a partnership between the industry and regulator.

The consultation document has rightly questioned some of our proposed initial settings and recommended others. In our view, the details of design should be carefully worked through with the affected parties.

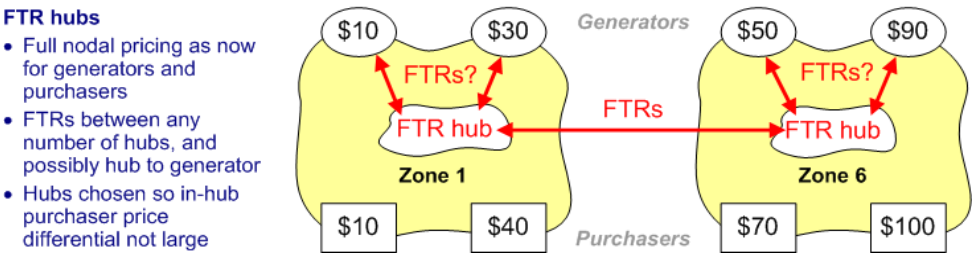
[15] Appendix 3 to consultation document "Managing locational price risk: Options", October 2009

6. Recommendations

We recommend that the Commission consider the following:

1. Adopting a high level process with the following principles:
    - phasing that provides options for development of hedging instruments over the long-term rather than making a single, major, change that locks in value transfers and limits future options;
    - consistency between all market development initiatives to ensure that locational price risk management works in concert with energy hedges/contracts to deliver full price certainty; and
    - alignment with international best practice in locational price risk management.

2. Consistent with the principles outlined in recommendation 1, initiate a process to implement Option 2 – FTRs, as a simplified mandatory hub-to-hub model, conceptually illustrated below:



With the following high level design considerations:

- an acceptable number of appropriately selected but mandated FTR trading hubs to be used for FTR trading not purchaser pricing, with hubs being chosen so that the in-hub purchaser price differential is not large;
- an allocation of residual constraint rentals and FTR auction income in a manner that is efficient and agreed by the industry;
- the ability, over time, for the market participants to reconfigure their energy contracts and FTRs to fully manage risk relative to the FTR hubs;
- if further encouragement of retail competition is found, over time, to be required, then consider evolving the FTR design or implementing a well considered alternative; and
- review of the FTR design parameters.

3. Abandoning the LRA concept in both its national or hybrid form, as we believe that it would entrench incumbencies, not promote competition

Appendix 1. Analysis of hybrid option – HVDC as offtake and negative offtake

This appendix provides example analyses of the revised consultation paper's hybrid model, examining issues of revenue adequacy and cost allocation. The examples are screen shots of the base 7-node case from Transpower's dispatch, LRA and FTR simulator, which is available at http://www.transpower.co.nz/dispatch-ftr-simulator.

In this model the North Island (NI) (with four nodes modelled) is assumed to be the HVDC receiving island, and the SI (with three nodes) to be sending.

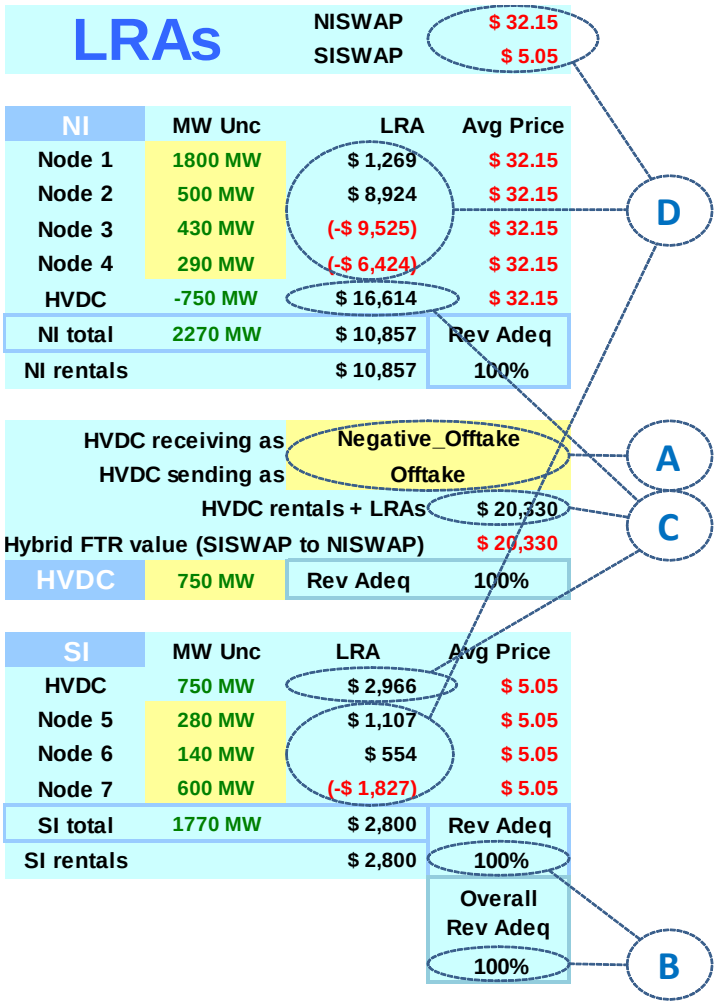
Example 1

In this example the HVDC treatment has been set at the revised consultation paper's stated preference of HVDC treated as negative offtake in the receiving island and as offtake in the sending island [A].

This HVDC treatment makes all aspects revenue adequate, as can be seen at [B] and at the separate island and HVDC 'Rev Adeq' boxes. The numbers balance.

The HVDC is made revenue adequate by the LRAs allocated to it from each island, $16,614 + $2,966 = $19,580. Along with the $750 rentals on the HVDC itself in this example, this makes $20,330 which exactly funds the inter-hub FTR = HVDC flow × (NISWAP – SISWAP) [C].

The issue is that this revenue adequacy for the inter-hub FTR is achieved by the LRAs to purchasers in each island being net negative, and relative to a significantly higher island-weighted price of $32 and $5 (compared to the $27 and $2 in the following example) [D].



Example 2

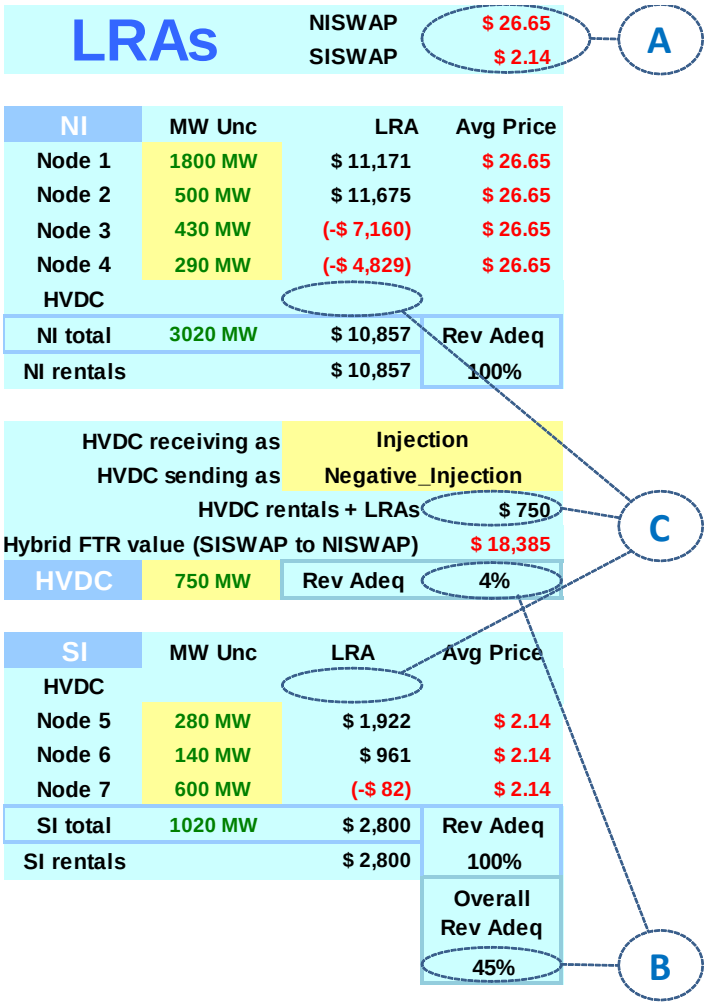
In this example the HVDC treatment has been set at the revised consultation paper's stated second preference of HVDC treated as injection to the receiving island and as negative injection in the sending island.

The ISWAP hub prices have decreased relative to example 1 to the $27 and $2 mentioned [A]. This is because the injection of cheap energy through the HVDC has been taken into account.

This HVDC treatment makes the HVDC FTR hugely revenue inadequate [B].

This is because the HVDC is not treated as offtake and is therefore not allocated any LRAs to supplement the HVDC rentals [C].

The receiving island hub price (e.g. NISWAP) can be much greater than the receiving node price (e.g. HAY) and the rentals necessary to let the FTR 'reach into' the hub have been used for the receiving island LRAs. An HVDC nodal FTR (e.g. BEN-HAY) would be viable, as it uses only the HVDC rentals, here $750.



Within each island zone, LRAs are revenue adequate, although this can require significant negative LRAs to achieve this. This is, in part, because the average receiving island generator price can be significantly above the HVDC injection price when there are constraints within the receiving island.

Appendix 2. Response to Commission Questions

Question	Transpower response	General comment
Q 1. *Do you agree with the LRA option providing a 100% hedge for all participating loads during constraints, noting that this involves some loads being required to make LRA payments? Please state the reasons for your position.*	No	An LRA provides a hedge to an arbitrary and ever changing, floating, zone price. If a purchaser has a contract for purchase at B and supply at A in an LRA zone that has a zone price of Z (where Z is the generation weighted average price) then the purchaser is exposed to the price difference Z-B (because the LRA payment hedges the purchaser to price Z not price B). Because a generator generates at A (and gets paid the price at A) and does not get an LRA payment the generator can never hedge between A and Z (or B) and therefore can never offer a fixed price at a location other than where it generates without taking on basis risk caused by congestion.
Q 2. Do you agree that the LRA option should have no LRA payments in relation to losses? Please state the reasons for your position.	Yes, assuming you agree with LRA as a solution to locational risk management.	Losses are relatively predictable. As such they should not require hedging.
Q 3. *Do you agree that participation in the LRA regime should require payment of a premium? If not, please state why*	No	LRAs will only work if they are mandatory. This is because some prices will be reduced to the LRA reference price and others will be increased to the LRA reference price. Given a choice, those who benefit will want LRAs and those that would otherwise have faced a lower price will not want an LRA. As the 'negative LRAs' are required to balance the financial flows, not having them will reduce the effectiveness of the 'positive LRAs'. It seems inappropriate to charge a premium for a price levelling mechanism that is not tradeable.

Q 4. *If the FTR option were applied, how many hubs should there be and how should they be defined?*	FTRs do not require hubs but a hub only model could be chosen with the number of hubs being a detailed design issue to be consulted on. Hubs should be chosen so that in-hub purchase price difference is not large.	The precise number of hubs necessary would be a detailed design feature that takes into consideration issues such as: • major load centres; • transmission constraints; • transmission pricing zones; • other zonal definitions existing within the broader transmission context. .
Q 5. *If the FTR option were applied, what duration should the FTRs have? Please state your reason for your recommended duration*	Duration should be a variable decided with FTR market stakeholders. There are benefits of starting with a short duration (say 1 month) to accelerate market learning, prior to moving to any preferred longer-term duration.	Market participants are likely to have energy contracts of duration which they would like FTR contracts to match in order to fully hedge their locational risk. FTR durations should be set to meet market requirements
Q 6. Within the FTR option, should the risk of revenue adequacy be apportioned to FTR	Appropriate risk sharing should be determined and agreed with	Revenue adequacy is driven by many factors. Risk should be properly understood and appropriately allocated to those who can manage that risk and for whom the risk provides incentives for efficient behaviour. This may be a combination of transmission provider, FTR

holders, the FTR market provider, the grid owner, or another party? Please explain the reasons why you prefer the option you have identified	stakeholders	market operator and FTR market participants.
Q 7. If the FTR option were implemented, how frequently should FTR auctions be held?	As required by market participants	A key driver of FTR auction frequency will be the FTR duration. For longer duration FTRs, periodic 'reconfiguration' auctions are likely to be appropriate. There is also the issue of FTR auction horizon, which is how far ahead of the FTR period an FTR auction is held.
Q 8. If the FTR option were implemented, should there be any pre-allocation of FTRs? If so, to whom and on what basis?	Yes, to those who pay for discreet assets. This depends on what kind of FTR market is implemented – see comment	FTRs are a financial proxy for physical property rights. If FTRs can be defined exclusively over assets that are being paid for by clearly defined parties, then those parties should receive the corresponding FTR(s) to ensure they are revenue neutral to the actions of others. In practice, this means only HVDC and spur lines, and then only if any mandatory hub definitions allow it.
Q 9. If the FTR option were implemented, how and to whom should any residue revenue be allocated? Please state your reasons why.	Use the current rentals allocation methodology and evolve as required.	Removes potential for costly value transfers at a time when market is undergoing significant development. It is consistent with the concept of pre-allocation to those that pay for assets, and unlike pre-allocation can be extended to model general cases, such as interconnection assets. However, if there are good reasons to change the allocation (methodology and/or recipients), and it is agreed with the industry, it would be appropriate to change the allocation.
Q 10. For the hybrid option, do you agree with the proposal to have FTRs traded between notional	No, as it is not technically possible	As modelling of LRAs demonstrates, there is no satisfactory means of creating an island-zone LRA and FTR hybrid. If you treat LRAs as designed by modelling the HVDC as injection, only a BEN-HAY rather than hub to hub FTR is possible. If you use LRAs to fund the HVDC

North Island and South Island supply hubs for managing inter-island congestion? If not, what alternatives would you recommend and why?		FTR from each zone, then the inter-hub FTR can work arithmetically but only by reducing purchaser LRA allocations in each zone, possibly to the point where they are net-negative.
Q 11. For the hybrid option, do you agree with the proposal that inter-island hedges should be scaled to reflect physical capacity on the notional inter-island interconnector? If not, what alternative would you recommend and why?	No. We recommend a simple settlement residues auction, should the hybrid model be implemented	See response to the previous question.
Q 12. If the zonal pricing option were applied, how many zones should there be and how should they be defined?	See response to question 4	See response to question 4. Zonal pricing will not of itself alleviate locational price risk. Zonal pricing would have to be implemented with risk management tool such as FTRs.
Q 13. If the zonal pricing option were applied, how should locational price risk between zones be managed? Please provide reasons in support of your recommended approach	Use FTRs	FTRs are the internationally preferred mechanism for hedging basis risk. LRAs do not provide an adequate means to hedge basis risk, are untied anywhere and will result in value transfers.
Q 14. Do you agree with	Partially	The Commission has identified the key costs and benefits and has

the Commission's approach to the high-level cost benefit analysis? Please explain why or why not		attempted to undertake a national net benefit analysis. We however, have very little confidence in the input variables.
Q 15. Have any key parameters been omitted from the cost-benefit analysis?		The consultation paper does not adequately quantify the national net economic benefits of any of its proposed options relative to the desired policy outcomes.
Q 16. Do you agree that the cost-benefit analysis has identified the best option for managing locational price risk? Please explain why or why not	No	The consultation paper does not adequately quantify the national net economic benefits of any of its proposed options relative to the desired policy outcomes. In the absence of this, and given how close and overlapping the cost benefit results were in any case, we do not believe that that the cost-benefit analysis in the consultation paper provides any robust basis for preferring one option over another. As explained in this submission, we believe that only one of the options (Option 2 – FTRs) achieves the desired policy outcomes, so the cost-benefit analysis should be whether that option is better than doing nothing. Given that the cost is primarily a one-off few million dollars, but the benefits relate to significant improvements in the levels of competition in a $7 billion per annum market, we do not believe that proving net benefit will be problematic.
Q 17. Do you support the Commission's initial preferred option of a hybrid LRA/FTR? Please state your reasons why or why not	No	LRAs do not provide adequate locational price risk hedging (see section 4.1 and section 4.3), are likely to mute demand side pricing signals and will introduce commercially disruptive value transfers.

Q 18. Are there any elements of the proposed design of the initial preferred option of a hybrid LRA/FTR that you would recommend changing? If so, please identify the element, your proposed change and the reasons for this	N/A	We do not believe an LRA to be a viable option for reasons stated in sections 4.1 and 4.3
Q 19. Do you agree with the proposed treatment of the costs of ancillary services required to support HVDC transfer, and associated rents?	No	No rentals (or equivalent market surplus) are currently being used to fund ancillary services. We disagree with the implications in parts of the consultation paper that rentals are or should be used to fund HVDC ancillary services. To do so would be equivalent to another allocation of rentals, namely to those parties that currently pay the ancillary service costs. It would also prevent, or significantly diminish, revenue adequacy of rentals-funded hedge products including FTRs. It is thus inconsistent with options 1, 2 and 3 (and not relevant to option 4).
Q 20. Do you consider that the initial preferred option of a hybrid LRA/FTR is the most effective option for promoting competition? If not, what changes would you recommend be made?	No	As outlined in sections 4.1 and 4.3 we do not believe that the hybrid LRA/FTR option provides the necessary opportunity to back-to-back an energy hedge/contract and therefore does not hedge basis risk. Vertical integration and regionalisation of generation and retail would remain. The hybrid LRA/FTR option would therefore not be effective in promoting competition in the electricity market. FTRs provide the means for matching an energy contract with a hedge against basis risk and are therefore preferred.