Application of FTRs to Hedging Strategy

Part 1: Summary Report

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with the assistance of

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September 2010

Quality Assurance Information

Name	LPR applications Sep-10 Part 1 v1.doc
File reference	E-Transpower-883
Issue Status	Issue 1, Draft
Issue Date	September 2010

Definitions

The following definitions, abbreviations and acronyms may be used in this report.

Aggregate location factor	The location factor used in adjusting hedge quantity to optimise hedging strategy without FTRs.
BEN	Benmore node BEN2201.
CFD	A hedge contract written as the difference between a fixed strike price and a spot price
Counter-party	The other party to an OTC hedge contract
Derivative	A contract who's value (cash settlement) is derived from some underlying variable(s). In the context of this report the underlying variables are spot prices.
EC	Electricity Commission (to be superseded by the Electricity Authority from October 2010)
FPVV	Fixed price variable volume
FTR	Financial transmission right. The EC proposes two classes: obligation FTR and option FTR.
Futures	A hedge contract traded on an organised exchange and subject to daily settlement. The counter-party in any futures contract is always the futures exchange.
FWAP	Futures-weighted average price
GIP	Grid injection point
GWAP	Generation weighted average price
GXP	Grid injection point
Hedge	Any measure taken, purchased or sold which is intended to offset a pre-existing risk relating to spot prices. In the context of this report, hedge generally refers to a financial instrument such as a CFD, futures contract or FTR.
Hedge ratio or Hedging ratio	The ratio of hedge quantity to the expected quantity of exposure to spot price
Location factor	The ratio of two spot prices in the same period.
LMP	Location marginal pricing (nodal pricing)
LPR	Locational price risk (also known as location factor risk or location basis risk)
LRA	Locational rentals allocation
MDP	Market Development Program
OTA	Otahuhu 220 kV node OTA2201 at Otahuhu, Auckland.
OTC	Over-the-counter market for CFDs and other non-futures electricity derivatives. Hedges in this market are traded directly between the parties to the hedge.
SME	Small-medium enterprises
Spread	A difference in the price of two financial instruments, assets or commodities
Strike price	The fixed price in a hedge contract
Synthetic FTR	An obligation FTR created by the sale and purchase of two futures contracts at different nodes for the same hedging period.
WKM	Whakamaru 220 kV node WKM2201 at Whakamaru on the Waikato River.

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Contents

Important Disclaimer

The information and formulae in this report are of a general nature and provided to inform and educate readers. However, the information and formulae should not be relied upon without the supporting data, analysis, testing, review and supporting processes that should accompany hedge strategy development and hedge trading. In particular, any hedge strategy should be understood, modelled and tested against a wide range of adverse scenarios before it is implemented.

This report is based on the information available to the authors at the time of writing in respect of the EC's LPR hedging proposal. The proposal was incomplete at the time and many gaps were filled by the authors, by making assumption or educated guesses. These assumptions and guesses may not be correct or appropriate in the context of the final implementation of LPR hedging.

Neither Energy Link nor Transpower will be held liable for the interpretation of, use of, or application of the information and formulae in this report.

1 Introduction

This report primarily describes the integration of new hedging instruments into hedging strategies for wholesale electricity market participants. The new instruments are proposed by the Electricity Commission (EC) as part of the on-going Market Development Program (MDP), and were also recommended by the Ministerial review of the electricity market undertaken in 2009.

Development of instruments for hedging locational price risk[1] (LPR) is included in the MDP, leading to a proposal being issued by the EC in September 2010. Energy Link was supported by Transpower to provide the market with independent information on how these instruments can be applied to hedging strategy. The information comes in two parts: this part (Part 1) is a summary report which includes the details of the proposal, and a series of worked examples showing how LPR hedges would be applied to hedging strategy.

Part 2 is a technical report which provides full details of the proposal including extensive development of the theory around FTRs and hedging strategy in the presence of LPR.

This report provides an overview of the EC's proposal to introduce LPR hedges in the form of Financial Transmission Rights (FTRs), and worked examples of how five different classes of market participants could include FTRs in their hedging strategies:

- independent retailer – buys at spot price to supply electricity to an electricity consumer, or to another retailer, but owns no generation;
- large consumer – purchases electricity at spot price and then hedges spot price risk;
- merchant generator – owns generation but has no retail, sells output at spot price and hedges the resulting spot price risk;
- gentailer – owns generation and is also a retailer;
- financial intermediary – is neither generator nor retailer, but trades in the hedge market.

Section 2 briefly outlines the EC's proposal. Section 3 includes formulae and worked examples for each of the five market participants listed above. Sections 4 through 13 cover other issues related to purchasing and owning FTRs.

FTRs are used to reduce or eliminate LPR, but other means of hedging LPR are available. Readers are referred to *Application of FTRs to Hedging Strategy, Part 2: Technical Report* for an explanation of these alternatives and a comparison of the relative pros and cons of each alternative.

GST is ignored in all worked examples in this report.

2 The EC's LPR Proposal

LPR arises for a market participant when their cash flows are determined, at least in part, by two or more spot prices. For example, a merchant generator may receive spot

[1] Also known as location factor risk or location basis risk.

revenue for their output at one node, which they hedge at a distant node. In this case the LPR is a function of the difference in the two spot prices, which varies over time.

The EC is currently consulting on a proposal to make inter-island FTRs available which reference island generator-weighted average prices (GWAPs), and which would be available as ‘obligation FTRs’ and ‘option FTRs’.

The payout on an obligation FTR would be given by

$$Payout = Q(H_B - H_A)$$

where Q is a fixed quantity in MWh per half hour, and H_A and H_B are the two GWAP prices, one in each island. This payout formula exposes the FTR purchaser to the possibility of having to pay cash to the FTR provider when settling the FTR.

The payout on an option FTR, on the other hand, is always positive, i.e. it is only activated when the payout is in favour of the holder of the FTR.

FTRs would be auctioned off to the highest bidders, and the auction proceeds distributed to parties paying transmission charges. Option FTRs would be expected to sell for a higher price than an obligation FTR.

Each month the losses and constraint rentals would be used to make FTR payouts, and the auction income and residual rentals left over from this process also distributed to parties paying transmission charges: lines companies, grid-connected generators, and grid-connected consumers. Lines companies would be encouraged to allocate their residual rentals and auction revenues to retailers who have customers on their respective distribution networks.

In the following table H_{NI} denotes the North Island GWAP hub price in a trading period and H_{SI} the South Island GWAP hub price. The hub prices in each island are the generation-weighted averages of all spot prices in the relevant island.

Table 1: Key Elements of Proposal

Design Element	Description
Obligation FTRs	Payout in each trading period equal to the difference between two GWAP hub prices, one in each island: Payout = $Q(H_{NI} – H_{SI})$ or Payout = $Q(H_{SI} – H_{NI})$ depending on which FTR is purchased Payouts occur regardless of whether the payout is positive or negative. If total payout over all periods in a month is negative, then purchaser must pay.
Option FTRs	FTR payouts as above, except that trading periods when the payout is negative are not included in the monthly settlement amount. Option FTR payouts will therefore always be positive.
FTR purchase	Obligation and option FTRs will be made available to FTR purchasers through regular auctions, and sold to the highest bidders. Quantities available will be limited to what can reasonably be expected to be paid from actual losses and constraints rentals[2].
Auction frequency	FTRs will only be available between the two island GWAP hubs and will each relate to one calendar month. The frequency of auctions is under discussion, but

[2] Ensuring FTRs are not oversold requires an analysis of “revenue adequacy” to be undertaken at auction time.

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Design Element	Description
	we expect them to be auctioned initially up to 24 months in advance. Under this scenario, each monthly auction would see one new FTR being introduced each month (for 24 months out) with shorter term FTRs being available up to the total quantity for which 'revenue adequacy' conditions are met, i.e. that all FTR payouts can be made from the rentals.
FTR specifications	Two products available - base-load and peak[3]: • 0.25 MW base-load: Q = 0.125 MWh in each and every trading period in the month; and • 0.25 MW peak: Q = 0.125 MWh in each and every trading period in the peak periods of the month.
FTR settlement	Undertaken by the spot market's Clearing Manager.
FTR performance guarantees	The EC's proposal lists a number of design features which either are already incorporated, or which could be incorporated, to ensure that all FTRs will be settled in full, i.e. to eliminate the need for provisions which could limit the payout on FTRs to one or more FTR purchasers in any given month.
Prudential requirements	Required only on obligation FTRs (for which the total payout in a month can be negative). No details are available from the EC at this point in time, but we expect similar requirements to those currently in place for purchases from the spot market.
FTR trading	Not covered in the EC's proposal but we expect that FTRs, once purchased, will be able to be traded with other market participants who meet the prudential requirements for FTRs.
Distribution of residual rentals and auction revenue	Undertaken by the (as yet un-named) FTR service provider.
FTR Service provider	A new service provider role to be created under the market rules to determine the specifications of FTRs, manage FTR auctions, and distribute residual rentals and auction income.

2.1 GWAPs

The EC's FTR proposal introduces the concept of a GWAP, or generation-weighted average price, for each island. These are also referred to as hub prices. For any particular trading period, a GWAP is defined as

$$GWAP_{illand} = \frac{\sum_{ALL\ GIPs\ in\ Island} (GIP\,injection) \times (GIP\ \ price)}{\sum_{ALL\ GIPs\ in\ Island} (GIP\,injection)}$$

The following two charts show estimated GWAPs[4], averaged by week, for each island, from 1 January 2004 to 31 July 2010, along with selected weekly average spot prices (these nodes are used in the worked examples in section 3).

[3] The definition of the peak period is not yet available, but could, for example, include all trading periods from 8 am to midnight each day in the month.

[4] These GWAPs were calculated by Energy Link, but were checked against a sample of GWAPs provided by the EC. There were small differences, but not significant in the context of the worked examples in this report.

Figure 1: North Island GWAP

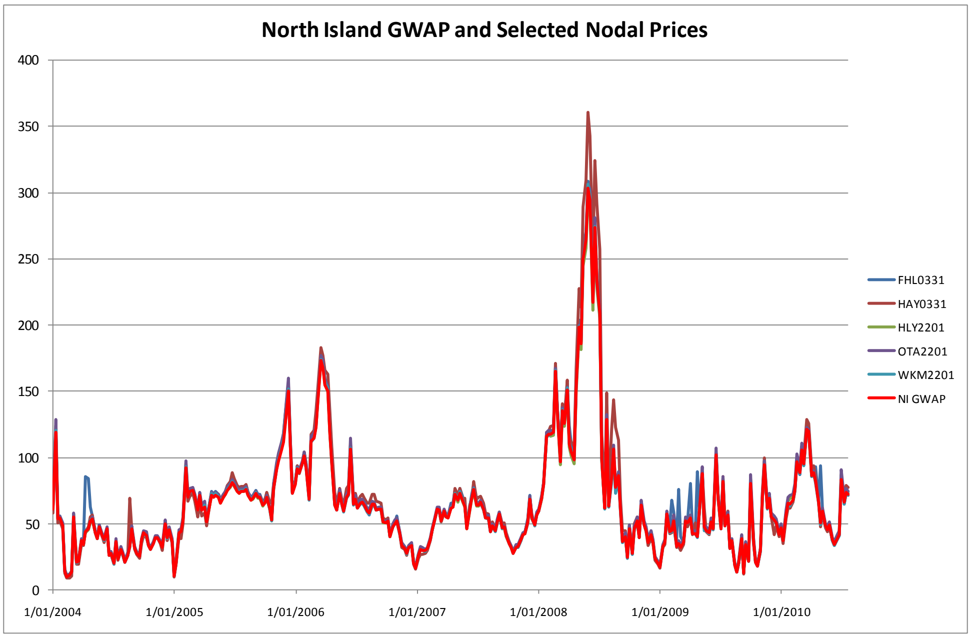


Figure 2: South Island GWAP

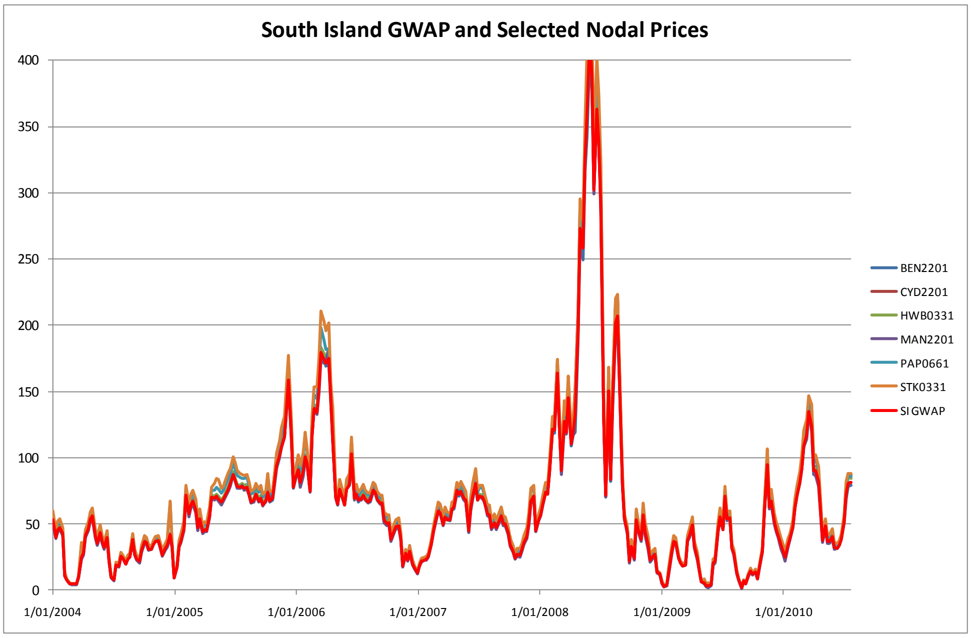
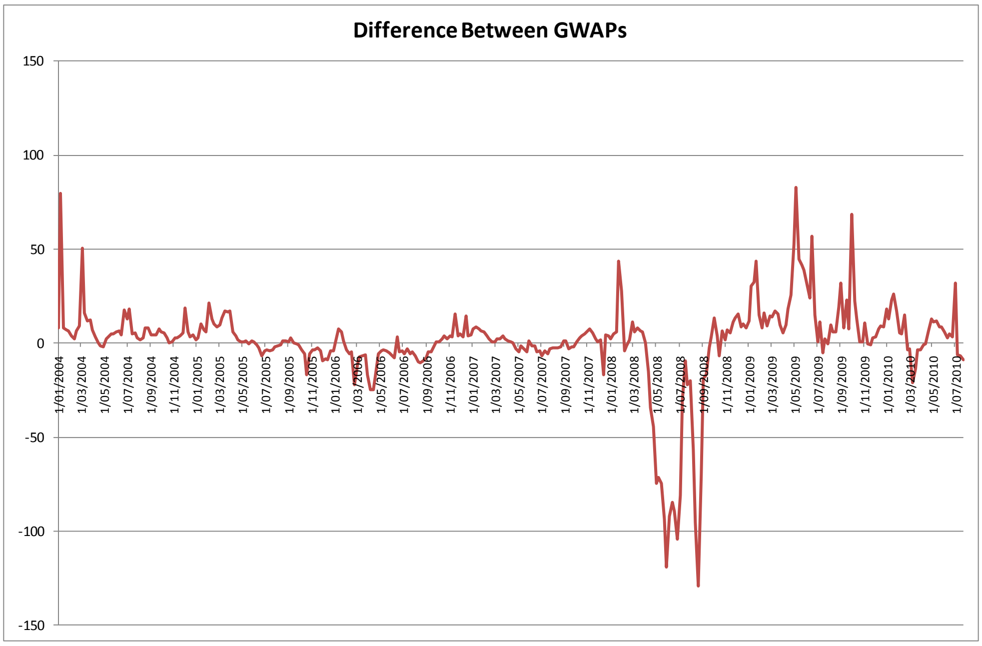


Figure 3 shows the difference between the two weekly average GWAPs (north minus south) and highlights the high degree of LPR between the islands. The large negative price difference in the 2008 dry year was driven by low inflows and falling storage in the South Island. More recently, higher inflows have seen power going primarily northward, but reduced HVDC link capacity has caused large positive price differences when the HVDC link has set the reserve risk in the North Island.

Detailed analysis is beyond the scope of this report, but work completed in and since 2009 by Energy Link and the EC has shown that, taken over the whole marke, the inter-island LPR is considerably more significant than intra-island LPR.

Figure 3: Difference Between GWAPs



3 Application of FTRs to Hedging Strategy

In this section we illustrate how FTRs could be applied to hedging strategy for the five classes of market participant: independent retailer, large consumer, merchant generator, gentailer, and financial intermediary.

The formulae given below are tailored to the EC's proposal which is to introduce FTRs only between the islands, thus hub prices H_A and H_B feature in all examples. In all cases the end result sought from the FTR is to eliminate LPR as far as is possible. Obligation FTRs are used in all worked examples, but option FTRs are discussed briefly in section 4.1.1.

The formulae also feature expected quantities that should be calculated using forecasts of future spot prices, load and generation. When these formulae are applied in real hedging situations, modelling should always be undertaken to determine the residual uncertainty and risks associated with the calculation of the expected values (i.e. errors in forecasts) and due to volatility in the underlying spot prices.

3.1 Independent Retailer

Consider an independent retailer who purchases from the spot market to supply its contracted customers at fixed prices. The fixed prices may either be in fixed price variable volume (FPVV) contracts typical of residential and SME customers, or in CFDs sold to large consumers.

Figure 4: Independent Retailer Exposure to LPR

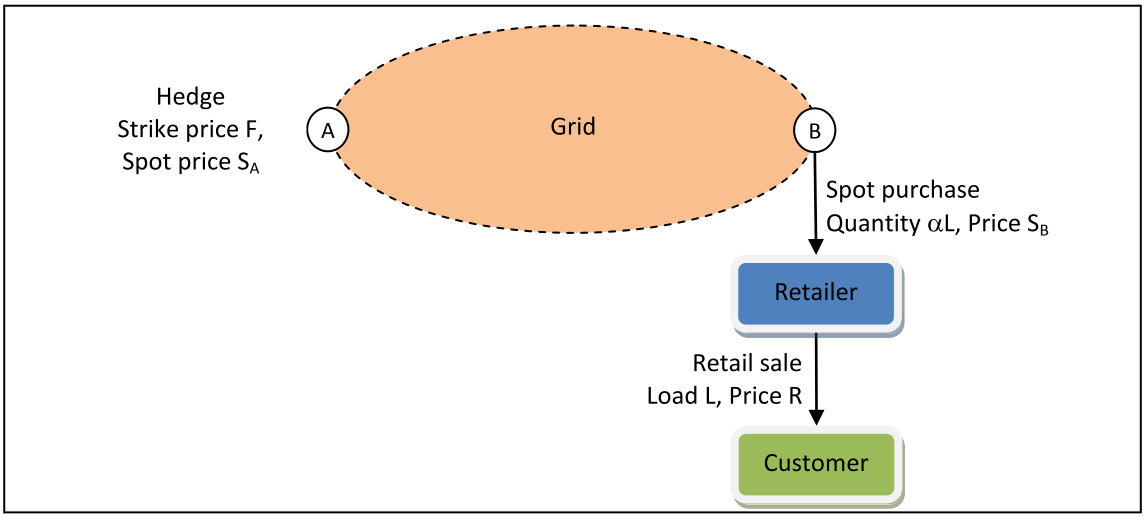


Figure 4 shows a period in which an independent retailer with FPVV customers at node B has total metered load of L. These customers are supplied at fixed price R but to supply these customers the retailer must purchase a larger quantity, αL MWh at spot price S_B at node B, where α is an adjustment accounting for losses incurred between node B and the customer's meters[5].

Focusing on what's happening at node B for the moment, and ignoring fixed costs and non-energy variable costs the retailer's gross profit is

$$GrossProfit = LR - \alpha LS_B = L(R - \alpha S_B)$$

which is to say that the gross profit is the metered sales volume, multiplied by the gross margin, which is the difference between the fixed sales price, R, and the variable loss-adjusted energy cost, S_B.

The gross profit has a significant element of price risk associated with it because the loss-adjusted spot price will at times exceed the retail price. Unless the retailer has some alternative means of hedging their price risk at node B, they will most likely seek some form of hedge to offset fluctuations in the spot price. They may achieve this by entering into some form of hedge at B: for example they might enter into a CFD with another party at B for up to 100% of their expected load at that node. This arrangement would reduce price risk and would not introduce LPR.

It often happens, however, that a retailer cannot find a cost-effective hedge at the node at which they have a spot exposure, and instead enter into a hedge at a distant node, in this example node A, which has a different spot price, S_A. Assuming the retailer aims for 100% hedge cover then the resulting gross profit is given by

[5] Losses between the grid and customer meters average just under 6% over a year, which translates into a loss factor α approximately equal to 1.064. This is a significant adjustment which does need to be taken into account in any hedging strategy.

$$GrossProfit = L(R - \alpha S_B) - Q(F - S_A)$$

where $Q(F - S_A)$ is the hedge, Q is the fixed hedge quantity and F is the strike price of the hedge. The hedge could be a CFD or it could be a futures contract.

We can also write the gross profit as

$$GrossProfit = LR - QF - (\alpha LS_B - QS_A)$$

which shows that there is now LPR associated with $\alpha LS_B - QS_A$. When the spot price at node B rises above the value given by $\left(\frac{Q}{\alpha L}\right)S_A$ then $\alpha LS_B - QS_A$ creates a negative cash flow.

Without some form of hedge against LPR, Q can be chosen so that on average $\alpha LS_B - QS_A$ is zero (or at least can be expected to be zero).

But let us suppose instead that nodes A and B are in opposite islands and that the retailer purchases an FTR which has payout $Q_{FTR} \times (H_B - H_A)$ where H_A and H_B are the respective island GWAP prices. Gross profit becomes

$$GrossProfit = RL - \alpha LS_B - Q(F - S_A) + Q_{FTR}(H_B - H_A)$$

To eliminate LPR and achieve a 100% hedge, we will choose the hedge and FTR quantity to be the same, so that $Q = Q_{FTR}$ and then we need to choose Q such that

$$Hedging\ ratio = \frac{Q}{\overline{\alpha L}} = \frac{\hat{S}_B}{\overline{H}_B + \overline{S}_A - \overline{H}_A}$$

which gives us the optimum hedging ratio as a function of the expected hub and spot prices. The hedging ratio is simply the hedge (and FTR) quantity divided by the expected loss-adjusted load.

There is some notation to become familiar with here:

- $\overline{\alpha L}$ is the average loss-adjusted off-take over the period of the hedge and FTR;
- $\hat{S}_B$ is the quantity-weighted average expected spot price at node B;
- $\overline{S}_A$, $\overline{H}_A$ and $\overline{H}_B$ are the time-weighted average prices at node A, hub A and hub B, respectively.

To make our lives simpler, in many applications we can also use $\overline{S}_B$ instead of $\hat{S}_B$, i.e. where αL is approximately constant over the hedging period being considered. Whether this simplification can be made or not requires checking the actual values of $\overline{S}_B$ and $\hat{S}_B$ to determine whether or not the error introduced by the simplification is significant.

In practice, the choice of parameters in our formula for the hedging ratio should be based on forecasts of each parameter and not on historical values. However, for the sake of simplicity the following worked examples use historical prices to show how the FTR performed in each case.

Consider a retailer supplying customers via GXP STK0331 (Stoke, at the top of the South Island), and hedged at HLY2201 (Huntly, south of Auckland) at a price of \$80/MWh, for the period from 1/1/2008 through to 31/12/2009, a total of two years[6]. As our focus is on price risk, we'll assume the retailer's loss-adjusted load is a constant 10 MW over the period, simplifying the calculation of quantity-weighted average expected spot prices. We also assume a fixed loss factor of 1.05 which gives metered retail load of approximately 9.52 MW or 4.76 MWh per trading period, sold at a constant retail price of \$120/MWh.

In this example our "A prices" are in the North Island and "B prices" in the South Island. Based on this historical data, the parameters we need are:

- $\overline{\alpha L}$ = 10 MW or 5 MWh per trading period;
- $\hat{S}_B$ = average price at STK0331 for the 2 years = \$89.97/MWh;
- $\overline{S}_A$ = average price at HLY2201 for the 2 years = \$78.39/MWh;
- $\overline{H}_A$ = average North Island hub price for the two years = \$78.65/MWh;
- $\overline{H}_B$ = average South Island hub price for the two years = \$81.26/MWh.

These give an optimum hedge ratio of

$$Hedging\ ratio = \frac{Q}{\overline{\alpha L}} = \frac{89.97}{81.26 + 78.39 - 78.65} = 1.111\ or\ 111.1\%$$

and hedge and FTR quantity of Q = 5 MWh × 1.111 ≈ 5.5 MWh per trading period or 11 MW.

Figure 5 shows an analysis of monthly gross profit over the two year period: total revenue is shown (Retail less Spot less Hedge plus FTR), but also the revenue that would have resulted if the retailer had purchased at spot price without hedging (Retail less Spot), and the revenue that would have resulted if the retailer had the hedge but not the FTR (Retail less Spot less Hedge).

The total gross profit for the period with the FTR is \$4,449,637, while without any hedging it is \$4,257,985, and with the hedge at Huntly only (no FTR) \$3,946,998.

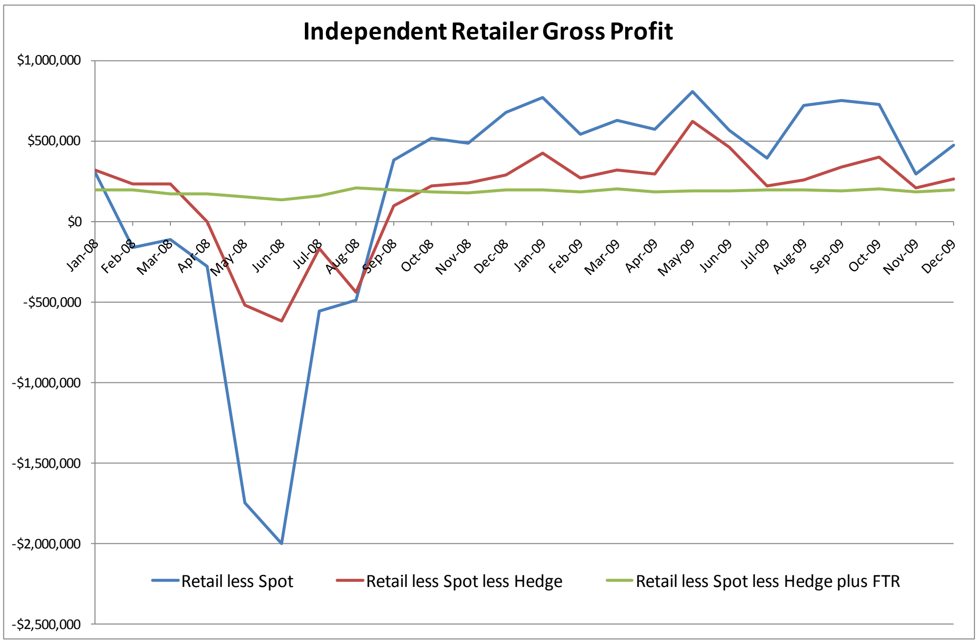
The chart illustrates a number of points:

1. purchasing at spot price without any hedging exposes the retailer to large swings in gross profit and negative cash flows;
2. adding a hedge in the other island has an impact on overall risk, but the retailer remains exposed to a significant degree of LPR;

[6] The EC's proposal is to make FTRs available for 2 years ahead.

3. adding the FTR to the hedging strategy significantly reduces the LPR and achieves positive gross profit throughout the period.

Figure 5: Independent Retailer Revenues



It is worth examining a trading period during the dry period in 2008 to aid understanding of how the FTR achieves such a dramatic reduction in the volatility of the retailer's gross profit. We consider trading period 7 on 12 June 2008, during which there is a large price difference across the HVDC link: the price at STK0331 is $396.41/MWh, the price at HLY2201 is $39.03/MWh, the South Island GWAP is $375.54/MWh and the North Island GWAP is $45.90/MWh.

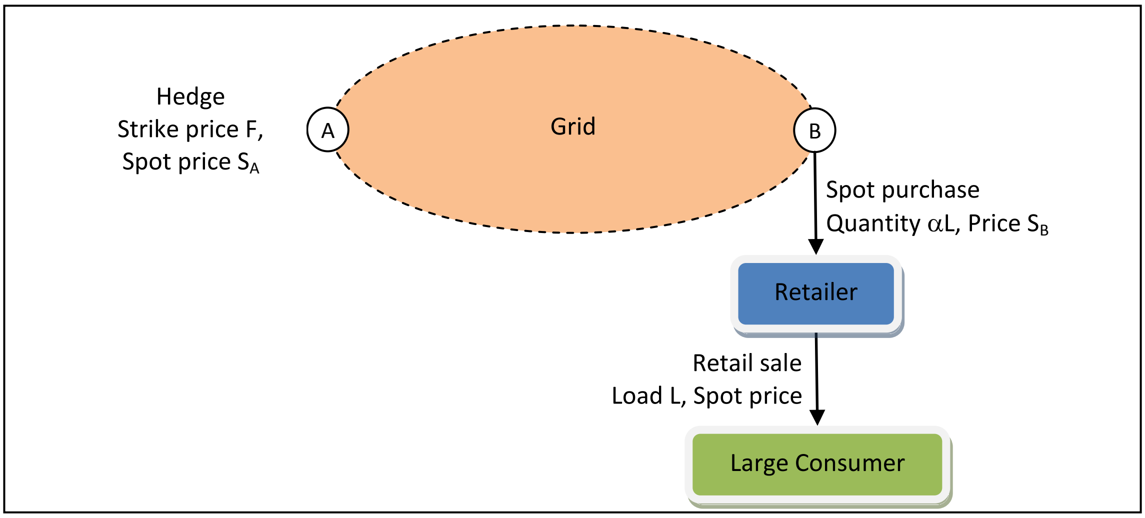
During this trading period the retail revenue is $571.20 but the spot cost of purchases to meet retail load is $1982.05. The hedge at Huntly actually costs the retailer $225.34 in this period (because the Huntly spot price is still below the hedge strike price of $80/MWh), but there is a $1,812.97 positive cash contribution from the FTR. Thus the FTR compensates for the poor performance of the hedge in this trading period.

3.2 Large Consumer

A typical purchasing arrangement for a large consumer "on spot" is shown in Figure 6, where the consumer purchases electricity at spot price via a retailer. Under this arrangement the large consumer pays for metered load plus losses at spot price, to give a total spot exposure of αLS_B in each trading period.

This arrangement has spot price risk, but no LPR until such time as the large consumer hedges the price risk, and then only if this is done at a distant node A (if a cost-effective hedge is not available at node B). Note that the hedge may be contracted with a party that is different to the retailer supplying the consumer at spot price.

Figure 6: Large Consumer Exposure to LPR



In this case the large consumer's cost is given by

$$Cost = \alpha L S_B + Q(F - S_A)$$

and the LPR is associated with $\alpha L S_B - Q S_A$. This situation is analogous to that of the independent retailer in section 3.1, so that if the consumer purchases an FTR then the optimum hedge ratio (where the hedge quantity at A and the FTR quantity are the same) to eliminate LPR is

$$\frac{Q}{\overline{\alpha L}} = \frac{\hat{S}_B}{\overline{H}_B + \overline{S}_A - \overline{H}_A}$$

Consider a large consumer with constant loss-adjusted load of 10 MW at FHL0331 (Fernhill, East Coast North Island), and a hedge at CYD2201 (Clyde, Clutha Valley in the South Island) at a price of \$80/MWh, over the two year period January 2008 to December 2009.

In this example our "A prices" are in the South Island and "B prices" in the North Island. Based on this historical data, the parameters we need are:

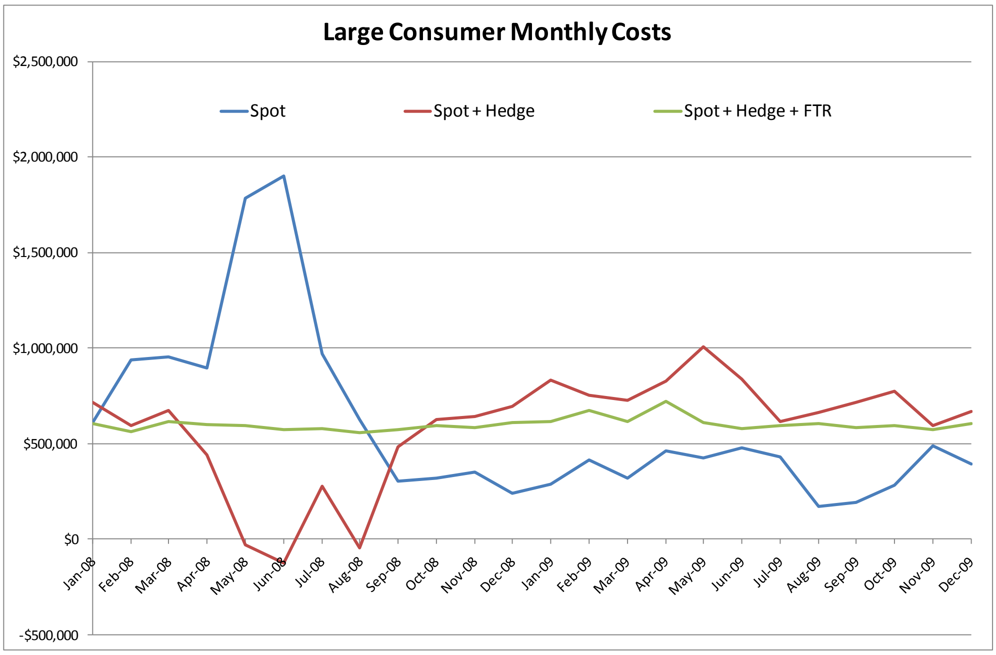
- $\overline{\alpha L}$ = 10 MW or 5 MWh per trading period;
- $\hat{S}_B$ = average price at FHL0331 for the 2 years = \$81.19/MWh;
- $\overline{S}_A$ = average price at CYD2201 for the 2 years = \$81.67/MWh;
- $\overline{H}_A$ = average South Island hub price for the two years = \$81.26/MWh;
- $\overline{H}_B$ = average North Island hub price for the two years = \$78.65/MWh.

These give an optimum hedge ratio of

$$Hedging\ ratio = \frac{Q}{\overline{\alpha L}} = \frac{81.19}{78.65 + 81.67 - 81.26} = 1.027\ or\ 102.7\%$$

and hedge and FTR quantity of Q = 5 MWh × 1.027 ≈ 5.1 MWh per trading period or 10.2 MW.

Figure 7: Large Consumer's Costs



Total monthly costs over the two years are $14,243,963 when completely un-hedged, $13,944,810 when the CYD2201 hedge is added, and $14,410,893 when the FTR is added.

Figure 7 shows that:

1. being fully on spot exposes the consumer to large increases in cost in dry years;
2. adding the hedge reduces the volatility in costs, and in this case reduces overall costs, but significant volatility in costs remains due to LPR;
3. adding the FTR significantly reduces LPR and gives the consumer a high level of certainty around monthly costs.

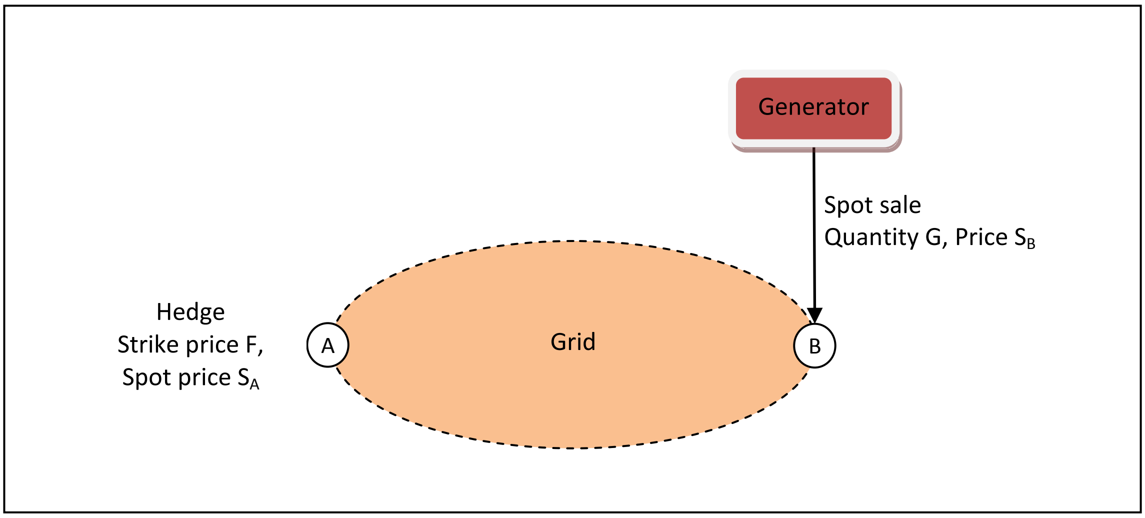
In trading period 7 on 12 June 2008, this time the spot cost is $204.35/MWh and the hedge at CYD22201 gives a positive cash contribution of $1,509.91 due to the price at CYD2201 being $376.06/MWh. However the FTR has a negative cash flow of $1,681.12/MWh because the FTR is an obligation FTR (and its payout can be positive or negative).

At this point one might be tempted to view the FTR as an additional cost to the consumer, over and above the hedge, which should have been avoided. However, this is not the point: the point is that the FTR helps reduce volatility in the monthly costs.

3.3 Merchant Generator

Figure 8 shows a merchant generator injecting at node B and receiving spot revenue from injection G. Their revenue risk is a function of the generated quantity and the spot price, and they may wish to reduce their net spot exposure with a hedge of some form.

Figure 8: Merchant Generator Exposure to LPR



If a cost-effective hedge cannot be sold at node B, then the generator may instead sell a hedge at node A in the other island, in which case their total revenue is given by:

$$Revenue = GS_B + Q(F - S_A)$$

If the generator wishes to eliminate LPR then they could purchase an FTR and then the optimum hedge ratio for the hedge at A and for the FTR is given by

$$\frac{Q}{\overline{G}} = \frac{\hat{S}_B}{\overline{H}_B + \overline{S}_A - \overline{H}_A}$$

The assessment of $\overline{G}$, the expected time-weighted average generation over the hedging period, must be made with more care than, for example, the assessment of the average load in sections 3.1 and 3.2 above. Generation may be constrained below expected levels just when constraints between the islands create large inter-island price differences. Therefore, analysis should be undertaken separately for periods within the overall hedging period when generation might or might not be constrained, to determine the overall impact of the FTR.

Consider a generator injecting a constant 10 MW at COL0661 (Coleridge, mid Canterbury) and with a hedge at HLY2201 (Huntly) at a price of \$80/MWh, over the two year period January 2008 to December 2009.

In this example our "A prices" are in the North Island and "B prices" in the South Island. Based on this historical data, the parameters we need are:

- $\overline{\alpha L}$ = 10 MW or 5 MWh per trading period;
- $\hat{S}_B$ = average price at COL0661 for the 2 years = \$83.63/MWh;
- $\overline{S}_A$ = average price at HLY2201 for the 2 years = \$78.39/MWh;
- $\overline{H}_A$ = average North Island hub price for the two years = \$78.65/MWh;

- $\overline{H}_B$ = average South Island hub price for the two years = $81.26/MWh.

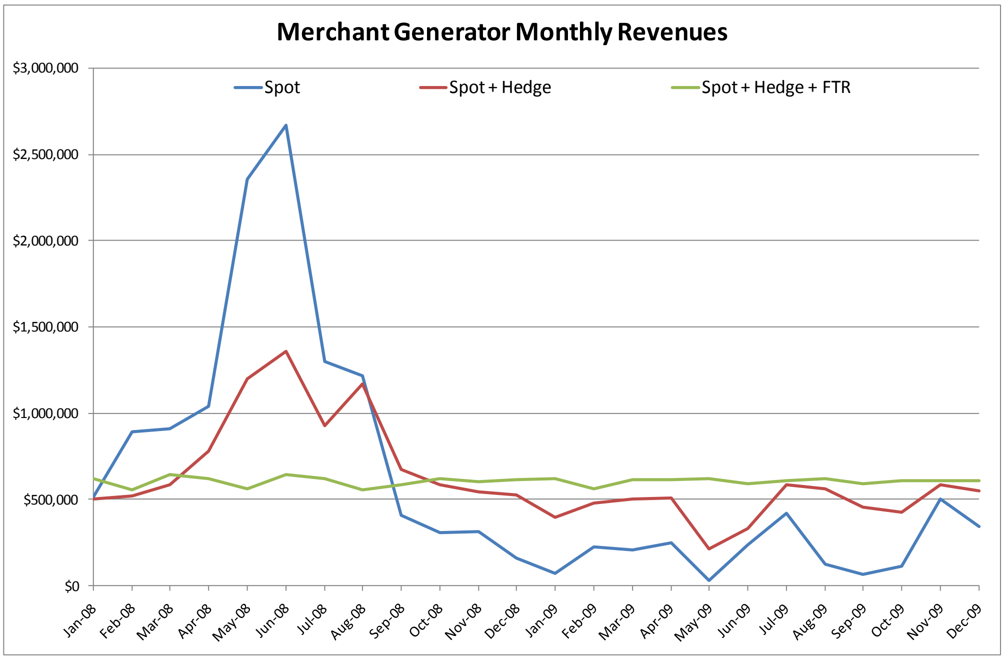
Assuming there the risk of this small generator being constrained to run below 10 MW is negligible, these parameters give an optimum hedge ratio of

$$Hedging\ ratio = \frac{Q}{\overline{G}} = \frac{83.63}{81.26 + 78.39 - 78.65} = 1.032 = 103.2\%$$

and hedge and FTR quantity of Q = 5 MWh × 1.032 ≈ 5.2 MWh per trading period or 10.4 MW.

Note that this time the FTR purchased has the form $Q(H_A - H_B)$, so payouts are in the opposite direction to the FTR considered above for the independent retailer and large consumer.

Figure 9: Merchant Generator's Revenue



Total monthly revenues over the two years are $14,671,806 when completely un-hedged, $14,965,830 when the CYD2201 hedge is added, and $14,490,608 when the FTR is added.

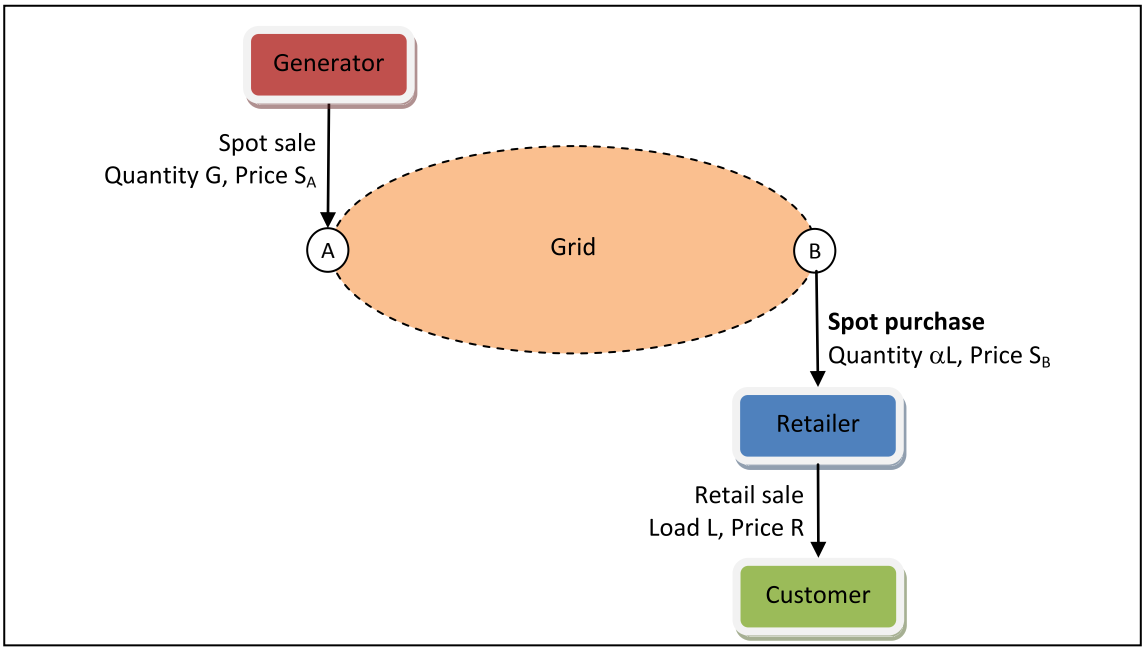
Figure 10 shows that:

1. being fully on spot exposes the generator to low revenues for long periods, e.g. in wet years;
2. adding the hedge reduces the volatility in revenue, and in this case increases overall revenue, but significant volatility in revenues remains due to LPR;
3. adding the FTR significantly reduces LPR and gives the generator a high level of certainty around monthly revenue.

3.4 Gentailer

A gentailer combines the functions of both a generator and retailer as shown in Figure 10 below. The gentailer's exposure to spot price comes from a revenue stream associated with generation at node A, and a spot purchase cost at node B associated with retail customers at node B.

Figure 10: Gentailer Exposure to LPR



Ignoring the marginal costs of generation, the gentailer's gross profit is given by

$$Gross\ profit = LR + GS_A - \alpha LS_B$$

While there is usually little ability to control customers' load, L, in any particular trading period, generation, G, might be able to be adjusted so that $GS_A - \alpha LS_B$ is kept close to zero, achieving little or no LPR, by setting generation to

$$G = \alpha L \frac{S_B}{S_A}$$

which is to say that a simple 'location factor[7] adjustment' would be made to generation, such that output should be set equal to the loss-adjusted retail load multiplied by the location factor of node B relative node A. What this would achieve, would be to obtain fixed gross profit equal to LR, but in fact it might be possible to generate more (or less) and achieve greater profits. In reality, it is impossible to know load and spot prices with certainty in advance, so the above formula would be applied using expected load and prices.

[7] A location factor is just the ratio of the spot prices at two nodes.

But constraints on the grid or limitations on the generator's output, may prevent G being set to this ideal value. The gentailer may therefore decide to purchase an FTR with quantity equal to the loss-adjusted load, αL, and in this case the generation required to minimise LPR in each trading period is

$$G = \alpha L\left(\frac{S_B + H_A - H_B}{S_A}\right)$$

Consider a gentailer with generation at HLY2201 (Huntly) and with a constant 10 MW loss-adjusted retail load at HWB2201 (Halfway Bush, Dunedin). We assume that the customers are supplied at a retail price of $120/MWh and that the loss factor is 1.05 to give net metered load of 4.76 MWh per trading period. We also assume the generator is able to set its output to between 5 MW and 15 MW while running.

In this example our "A prices" are in the North Island and "B prices" in the South Island, and this time the FTR purchased has the form $\alpha L(H_B - H_A)$.

Figure 11: Gentailer's Gross Profit

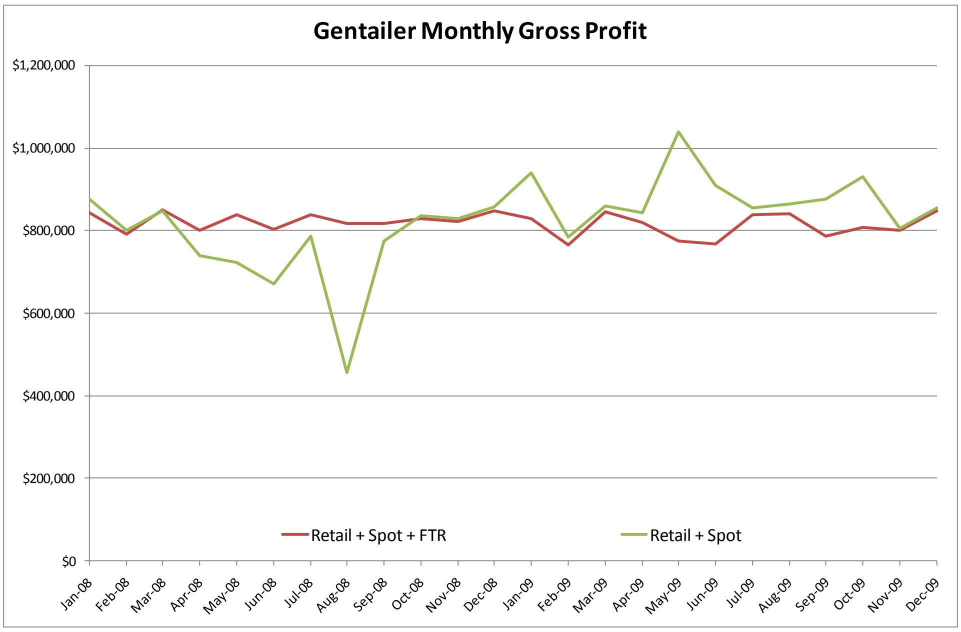
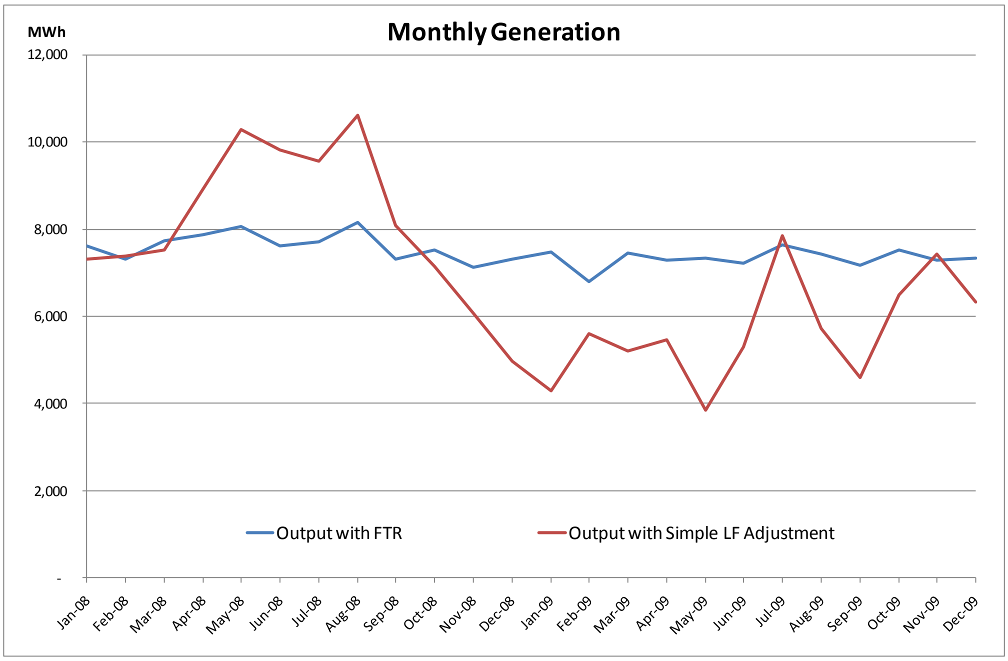


Figure 11 shows a 'Retail + Spot' curve in which generator output is set to the loss-adjusted load multiplied by the simple location factor S_B/S_A, and a 'Retail + Spot + FTR' curve in which generator output is set to the loss-adjusted load multiplied by $(S_B + H_A - H_B)/S_A$. In both cases output is limited to vary between 5 MW and 15 MW.

Adding the FTR reduces the volatility in monthly gross profit, and it also reduces the volatility in generator output, as shown in Figure 12.

Figure 12: Gentailer's Generator Output



By adding an FTR, therefore, the gentailer has:

1. minimised LPR in respect of the separation between their generation and retail load, stabilising monthly gross profit; and
2. reduced the volatility in generator output month by month.

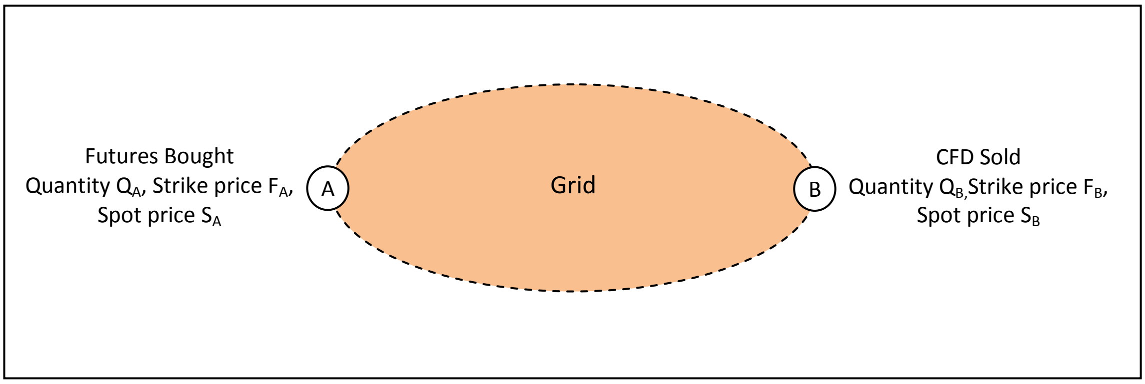
3.5 Financial Intermediary

At this point in time there are no financial intermediaries trading directly in electricity markets in New Zealand, but the development of the electricity futures market is likely to attract new financial players to our market. The experience in Australia is that financial institutions have entered the market to act as intermediaries[8] between the futures market and the "over-the-counter" (OTC) hedge market[9].

For example, an investment bank with an existing energy trading function in Australia, might decide to enter the New Zealand market and offer CFDs, but without also being a trader in the spot market. If they sell a CFD, this creates an exposure to the spot price, which they might then offset in the futures market by buying a futures contract. Ideally, the futures would be bought at the same grid node as the CFD, but if this cannot be achieved then LPR arises, as shown in Figure 13.

[8] Others have entered the Australian market as pure traders.
[9] In the OTC hedge market, hedges are traded directly between the parties to the hedge.

Figure 13: Financial Intermediary Exposure to LPR



In Figure 13 the intermediary's total hedge settlements[10] are given by

$$Q_B(F_B - S_B) - Q_A(F_A - S_A) = Q_B F_B - Q_A F_A + Q_A S_A - Q_B S_B$$

which indicates LPR associated with $Q_A S_A - Q_B S_B$. To reduce LPR, the intermediary may choose to set the hedge quantities such that

$$\frac{Q_A}{Q_B} = \frac{\bar{S}_B}{\bar{S}_A}$$

which is to say that the hedge quantities would be related to each other by the expected location factor between the two nodes over the hedging period.

If, on the other hand, they purchase an FTR $Q(H_B - H_A)$ then

$$\frac{Q_A}{Q_B} = \frac{\bar{S}_B + \bar{H}_A - \bar{H}_B}{\bar{S}_A}$$

Consider an intermediary who has sold a 10 MW hedge at PAP0661 (Papanui, Christchurch) at a price of \$85/MWh, and bought 10 MW of futures contracts at OTA2201 (Otahuhu, Auckland) at a price of \$80/MWh, covering the two year period January 2008 to December 2009.

In this example our "A prices" are in the North Island and "B prices" in the South Island. Based on this historical data, the parameters we need are:

- Q_B = 10 MW or 5 MWh per trading period;
- $\bar{S}_B$ = average price at PAP0661 for the 2 years = \$87.37/MWh;
- $\bar{S}_A$ = average price at OTA2201 for the 2 years = \$80.98/MWh;
- $\bar{H}_A$ = average North Island hub price for the two years = \$78.65/MWh;

[10] In reality, this formula ignores the fact that futures contracts are subject to daily settlement. The settlements on the futures should be regarded as notional settlements. Total settlements over the two year period in the worked example work out to be the same whether futures or CFDs are used.

- $\overline{H}_B$ = average South Island hub price for the two years = \$81.26/MWh.

Without the FTR, these parameters give an optimum quantity of futures of

$$Q_A = 5 \times \frac{87.37}{80.98} = 5 \times 1.079$$

which is approximately 5.4 MWh per trading period.

With an FTR, these parameters give an optimum quantity of futures of

$$Q_A = 5 \times \frac{87.37 + 78.65 - 81.26}{80.98} = 5 \times 1.047$$

which is approximately 5.2 MWh per trading period.

Figure 14: Intermediary's Notional Revenues

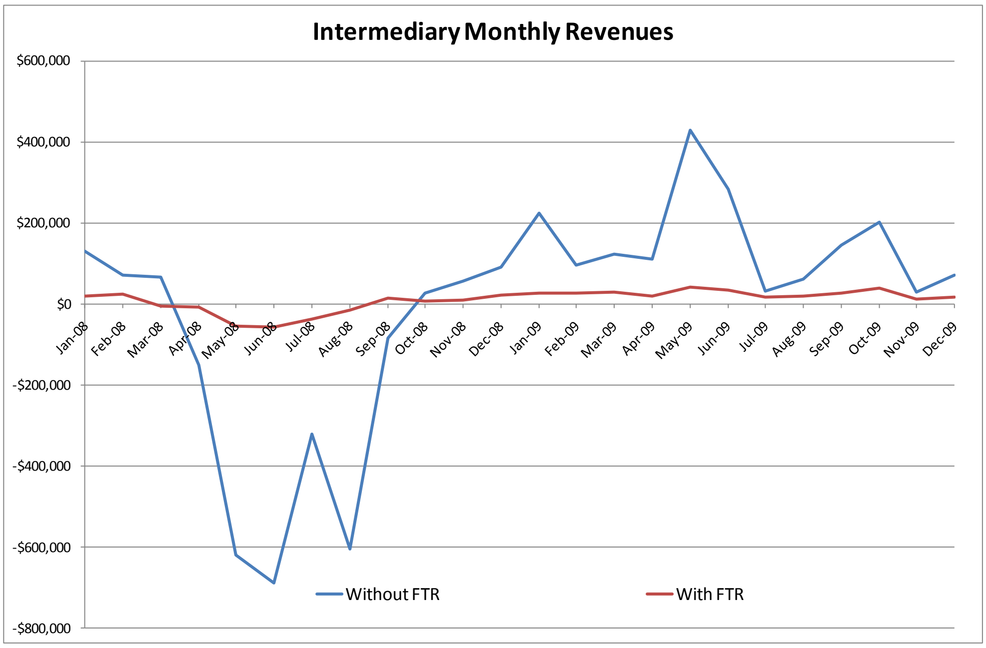


Figure 14 shows notional revenues associated with the intermediary's hedging strategy. In actual fact, they have purchased futures contracts at OTA2201 and these are subject to daily settlement, meaning that the notional revenues do not necessarily represent the actual cash flows on the futures contracts. Ignoring the impact of daily settlement, the notional revenues show that adding the FTR to the intermediary's hedging strategy significantly reduces volatility associated with LPR. With the FTR the total net revenue for the period is \$220,831 and without the FTR -\$229,224.

3.6 FTR Purchase Considerations

Figure 5 showed monthly gross profit in accounting terms for an independent retailer, but the cash flows would actually occur in the month following. In addition, the retailer would purchase the two years of FTRs some time prior to January 2008.

Let us suppose that the retailer expected the North Island GWAP to average $78/MWh over the period, and the South Island GWAP $80/MWh, thus the expected price difference in the southward direction was $2/MWh. Based on a quantity of 11 MW, or a total quantity of 192.72 GWh over the two year period, the total purchase cost of the FTR would be expected to be $385,440. Let us suppose they bid this amount and won the two years of FTRs in one go, in which case $385,440 would be paid out immediately after the auction: this is a significant amount of money in relation to the monthly gross profit associated with the load being hedged, the timing of which could impact on FTR purchasing strategy.

These considerations around the cash flow implications of the initial purchase of an FTR, apply equally in the other worked examples above.

3.7 Form of the FTR

The form of FTR assumed in this report (and in Part 2) is given by $Payout = Q(S_B - S_A)$. However, previous designs for FTRs had the slightly more complex form given by $Payout = Q(S_B - L_{AB}S_A)$ where L_{AB} is the average 'loss factor' between nodes A and B.

Loss factors are typically numbers close to one, and this small adjustment is required in a full FTR regime to ensure revenue adequacy, i.e. to ensure that the losses and constraint rentals fund all FTR payouts (at least on average). This is required because only half of the inter-nodal price impact of losses is present in the rentals.

If the loss-adjusted form is used, then the loss factor must be included in the location factor adjustments given in this report and in Part 2. For example, the formula for the independent retailer (section 3.1) becomes

$$\frac{Q}{\overline{\overline{\alpha L}}} = \frac{\hat{S}_B}{\overline{\overline{H}}_B + \overline{S}_A - L_{AB}\overline{\overline{H}}_A}$$

In other words, wherever S_A appears in the formulae above, $L_{AB}S_A$ would appear.

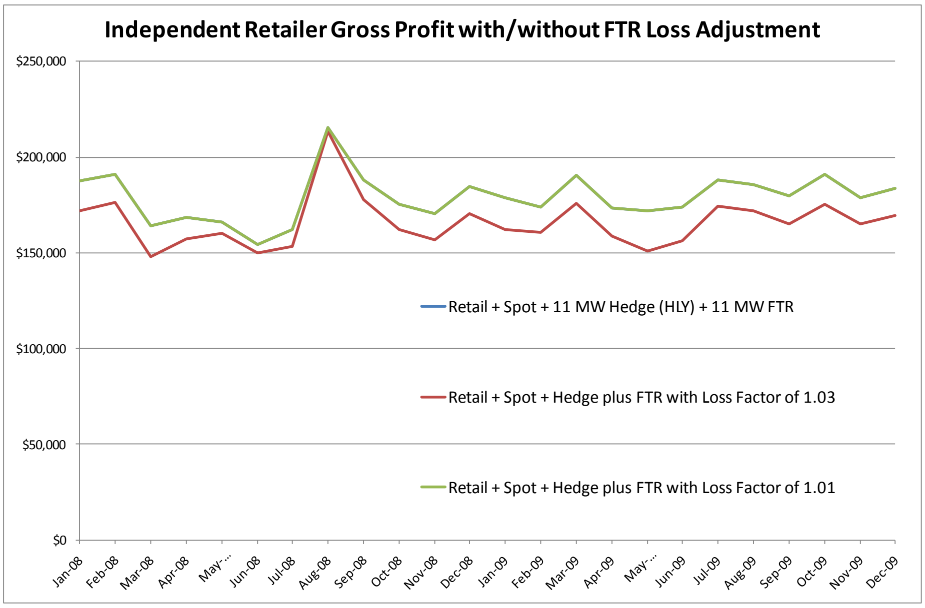
For the independent retailer example, with an inter-island loss factor of 1.01, this example would lead to a hedging ratio of

$$Hedging\ ratio = \frac{Q}{\overline{\overline{\alpha L}}} = \frac{89.97}{81.26 + 78.39 - 1.01 \times 78.65} = 1.100$$

and hedge and FTR quantity of Q = 5 MWh × 1.100 ≈ 5.6 MWh per trading period or 11.2 MW. A loss factor of 1.03 would give an FTR quantity of 5.7 MWh per trading period or 11.4 MW. Total losses on the grid average just over 3%, so the inter-island loss factor is likely to be in the range 1.01 to 1.03 on average.

Figure 15 shows the independent retailer's monthly gross profit as it was in section 3.1 with FTR of form $Payout = Q(S_B - S_A)$, and also with an FTRs with a loss factor included of 1.01 and 1.03 (with FTR and hedge quantity set to 11.2 MW and 11.4 MW, respectively).

Figure 15: FTR With and Without Loss Adjustment



The chart shows that the inclusion of the loss adjustment reduces the effectiveness of the FTR only slightly, provided the quantity adjustment is made correctly. The effectiveness of the FTR is quite sensitive to its quantity.

3.8 Applications Summary

The worked examples in section 3 have all shown that adding an FTR to a hedging strategy where there is LPR between the islands significantly reduces that LPR and volatility in monthly cash flows. The majority of LPR in the market as a whole is between the islands, and the examples show that the use of FTRs can make inter-island hedging viable.

There is residual LPR within each island, but the quantity adjustments derived in *Application of FTRs to Hedging Strategy, Part 2: Technical Report* were applied in the examples in optimal fashion.

4 FTR Purchasing Strategy

It is proposed that FTRs be available by month for up to 24 months in advance, and that they be available as either base-load or peak products. In the latter case the FTR would only cover those periods in each day of the relevant month deemed to be in the peak period, e.g. 8 am to midnight or 7:30 pm to 11 pm[11]. The availability of these two types of FTRs would allow participants to create a profiled LPR hedging strategy.

For example, an LPR hedge could be formed from one base-load FTR and one peak FTR, which would cover a retail exposure to inter-island LPR more reflective of a typical mass market load profile than would a base-load FTR on its own.

The FTRs would be available as 0.25 MW products, which equates to an FTR hedge quantity of 0.125 MWh per trading period.

[11] The EC has not yet specified a peak time zone.

A purchasing strategy for FTRs will need to consider a number of issues in relation to the number of FTRs purchased in any given month, a few of which are listed below.

- Which way should the payout be on the FTR? There is a big difference between an FTR paying out on $H_A - H_B$ and one paying out on $H_B - H_A$, and considerable needs to be taken to ensure that an FTR is not purchased in the wrong direction.
- What is the forecast MW exposure at spot price over the coming 24 months? Does this exceed the minimum FTR volume of 0.25 MW (purchasing FTRs in excess of the forecast spot exposure volume amounts to speculation rather than hedging)?
- What is the demand for FTRs in general? A fall in forecast spot exposure could result in being over-hedged with FTRs, and the need to sell FTRs in future: is the FTR market showing signs of enough trading to allow an FTR sale to occur at a reasonable price?
- Consider a 'portfolio approach' to FTRs: purchase more FTRs for earlier months, less for later months, e.g. if forecast spot exposure is uncertain, and being over-hedged with FTRs is to be avoided.
- Is now a good time to be purchasing FTRs, or should the purchase be delayed? For example, the market may be under stress with FTR prices sitting high, so delaying purchase may be prudent (or offer a lower price). Consider purchasing FTRs well in advance (6 months or more) during periods when FTRs are available at reasonable cost.

4.1.1 Obligation versus Option FTRs

EC proposes that FTRs be offered in two classes:

1. obligation FTR settlements work in both directions, so may have negative cash flow in any given month;
2. option FTRs payout only when in the purchaser's favour, but will probably sell for a higher price than obligation FTRs.

Which class of FTR is purchased should be based on an understanding of whether or not the purchaser's underlying spot exposure is symmetric or asymmetric. An asymmetric exposure would occur, for example, when large price differences in one direction (e.g. $H_A - H_B$) are more likely to be higher and more sustained than large price differences in the other direction ($H_B - H_A$).

In section 3.1 we considered an independent retailer who purchased an FTR to reduce LPR associated with retail load in the South Island and a hedge in the North Island, and we assumed the expected price difference between the two islands hubs was positive in the southward direction.

In fact, the expected price difference between the islands is still typically positive in the northward direction. In section 5 we state that the price of an FTR, all other things being equal, is established by the expected price difference between the hubs. If that difference is negative, then this implies a negative price would apply. However, FTRs will be sold at auction, not given away with cash, so in practice an FTR purchaser would need to offer to buy an FTR with negative price for a positive price, which implies a premium would be paid for it.

Alternatively, an option FTR could be purchased instead. Since option FTRs only have positive payouts, their price will always be positive.

5 Pricing FTRs

An important consideration when bidding to purchase an FTR is the price that will be bid. For an obligation FTR, the price per MWh of FTR quantity should, in theory be the expected difference between the two spot prices referenced in the FTR over all trading periods covered by the FTR. Pricing an FTR therefore requires that an assessment be made of expected spot prices, which can be done either by using a forecast, or by reference to prices for nodes in the futures market:

FTR Price per MWh = $E[H_B] – E[H_A]$ or FTR Price per MWh = $E[H_A] – E[H_B]$

From time to time, or if market power is an issue in respect of FTRs, prices may vary from this theoretical ideal. In addition, every market participant has their own view on future prices, so it each market participant must make their own assessment of their FTR bid price.

Option FTRs are priced in similar fashion, the difference being that only the periods when the FTR is expected to payout are considered in the pricing analysis. Given that the proposed FTRs are inter-island, this inevitably leads to a higher price for option FTRs than for obligations FTRs.

6 Procuring and Trading FTRs

To bid for FTRs, market participants will register with the FTR service provider and will be required to sign an FTR contract. This may occur once an FTR is purchased, or it could be that a master FTR agreement is signed, after which individual FTRs are added as transactions as they are purchased.

Auctions will be conducted monthly for each of the next coming 24 months. Bidders will submit bids, but some or all may not be accepted. FTR settlements are funded by the losses and constraint rentals left over in the spot market each month, and it is possible to sell so many FTRs that their settlements are not covered by the rentals. The FTR service provider will therefore only accept bids which are consistent with FTR ‘revenue adequacy’, which means that the FTRs can be settled from the rentals, but no more. We expect that bids will be accepted in price order from highest to lowest until either all bids are accepted, or revenue adequacy is about to be violated. Further details are not yet available from the EC.

6.1.1 Prudential Requirements

FTR purchasers will be required to meet prudential requirements in respect of obligation FTRs, which may be a significant barrier for some market participants. Details are not yet available, but we expect that these will operate in a manner consistent with the prudential requirements for spot purchases[12]: cash deposits, suitable credit rating, letters of credit or other instruments will be required to a level that guarantees settlement.

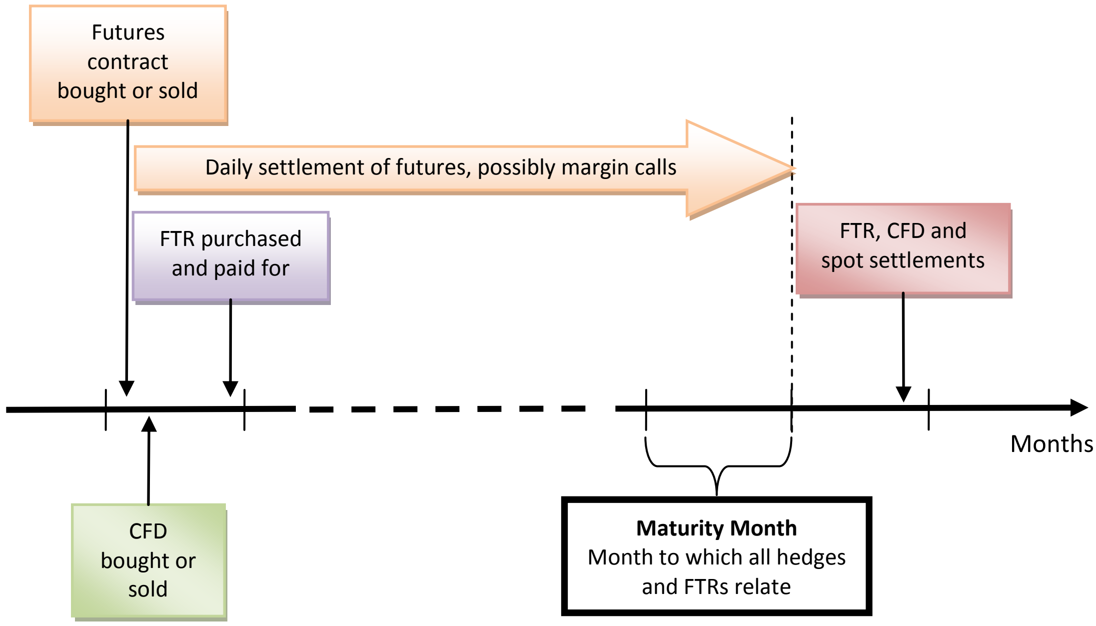
[12] FTR settlements will be undertaken by the Clearing Manager who also settles all spot purchases and spot sales.

While these requirements will apply to obligation FTRs, which give negative cash flows, they will not apply to option FTRs which are always cash flow positive.

7 FTR Settlements and Cash Flows

Figure 16 shows the timing of various cash flows in the market.

Figure 16: Cash Flow Timing



The month to which all hedges and FTRs relate to (the maturity month) could be up to 24 months in the future. The FTR is purchased at auction and is likely to be settled in the same month in which it is purchased. If a CFD is bought or sold at the same time as the FTR is purchased, no cash is exchanged on the CFD until the month following the maturity month.

Futures, on the other hand, are subject to daily settlement, with the possibility of having to meet margin calls, from the first business day after they are bought or sold. But at the end of the maturity month the futures contract is fully settled[13].

In the month immediately following the maturity month, spot purchases and sales are settled, the CFD is settled and the FTR is settled.

CFDs have the advantage that their cash flow timing closely matches the cash flows of the spot market. But FTRs require a potentially significant cash outlay shortly after they are purchased, which is potentially 24 months ahead of the maturity month. The different timing of FTRs and futures can create cash flow management issues for electricity market participants, which must be carefully considered before transacting in either instrument.

[13] A futures contract settles against the futures price on all days until the last day of the maturity month when it settles against the average spot price for the month.

8 Performance Guarantees

When FTRs were proposed in the past, a major negative was the potential for the rentals to be insufficient to settle all FTRs. In such a case, FTR payouts would be scaled down to fit within the rental funds available. In its proposal, the EC has taken some pains to include measures which would reduce the possibility of this happening:

- the FTRs cover only inter-island LPR so total rentals in each month include intra-island rentals, hence the total rentals pool available is likely to exceed the FTRs payouts in most cases;
- use of FTR auction income where rentals are insufficient.

The EC has not completely eliminated the risk of the rentals being insufficient, which does leave the possibility of scaling of payouts, but the above two measures are likely to reduce the possibility of scaling to insignificant levels.

9 Resource and Tools

Staff with appropriate skill and tools will be required to support the purchase, trading and settlement of FTRs at various points in the life-cycle of each FTR, and to optimise the application of FTRs to hedging strategy.

An FTR should be priced as the expected hub price difference for the nodes concerned, which is then multiplied by the quantity to give the full bid price. The formulae for hedge and/or FTR quantity also require the estimation of quantity-weighted or time-weighted average spot or hub prices, so the methods used to calculate these are similar or identical to the methods used to calculate expected hub prices. A significant degree of forecasting and analysis is required to calculate these expected hedging parameters.

If there is sufficient liquidity in the futures market then FTRs will also be able to be priced by reference to the difference between the futures price at nodes in different islands, e.g. between BEN and OTA, or BEN and WKM[14]. The FTRs reference GWAP hub prices, but the location factor difference between GWAP hubs and futures nodes can be assessed as are other location factors, so the use of GWAP prices is only a minor complication in this regard.

The tools usually employed to estimate expected spot and hub prices, and location factors, are typically models which forecast spot prices by some means, including the ability to run scenarios covering a range of possible future scenarios. Smaller players that cannot justify these resources may also be able to infer others' forecast prices by reference to publicly disclosed data including the hedge data disclosed by the EC, for example.

10 Financial Reporting Requirements

FTRs are financial instruments (derivatives) whose value depends on spot prices, so there will be a requirement to value these and include changes in value in the Statement of Financial Performance (profit and loss statement).

[14] WKM may be introduced as a futures node.

All financial instruments including FTRs are recognised on the balance sheet at "fair value" which is defined as "the price at which the FTR could be exchanged in a current transaction between knowledgeable, unrelated willing parties". The fair value likely to change from year to year so will impact on reported profit.

To calculate fair value, there is a hierarchical approach to follow:

1. use quoted prices if the FTR is traded on a fully liquid market;
2. use quoted prices for similar instruments in a liquid market, e.g. estimate the value using current futures prices at nodes in two islands;
3. other methods, e.g. use a forecast of the FTR's expected price difference.

Hedge accounting rules allow the FTR purchaser to match changes in the fair value of the hedge with changes in the underlying hub price difference, which means that changes in fair value will not impact on profits. To apply hedge accounting the FTR must be able to be shown to remain between 80% and 125% effective throughout its life, which would be simple matter for an FTR except when there is a significant possibility of the FTR payout being scaled, or if the location factor between the FTR's GWAP hubs and the nodes where the spot exposure actually occurs moves significantly.

11 Restrictions on Dealing in FTRs

FTRs will meet the definition of an "electricity futures contract" contained in the Authorised Futures Dealers Notice No 3, 10 April 1997, issued pursuant to the Securities Markets Act 1988, which restricts dealing in electricity derivatives to retailers, generators, lines companies, DHBs, members of MEUG, registered banks, public bodies, consumers using over 10 GWh pa, and the financial community (investment businesses and large private investors).

12 Residual Rentals and Auction Income

There is not a lot to add to the EC's proposal for the distribution of rentals (after settling FTRs) and FTR auction income (the benefits to retailers of having lines companies pass rentals revenue are significant), except to say that receiving these distributions is a weak hedge against LPR in most cases (the exceptions being South Island generators who receive HVDC rentals). The distribution methodology is tied to payment of transmission charges which does not necessarily relate well to where rentals are generated.

However the introduction of FTRs will serve to reduce the volatility in these distributions so market participants may look to count on them as a more reliable revenue stream than it has been in the past.

13 Market Power Issues

The use of FTRs for hedging LPR raises the issue of market power in respect of FTRs, the concern being that a market participant that is in a position to influence the value of $H_B - H_A$ will be prepared to bid higher than other market participants, thus reducing the availability of FTRs, and leading to less than ideal FTR pricing.

The possibility that market power could be used in respect of FTRs, could make FTRs more or less attractive as a hedging instrument than alternative means of hedging LPR.

Market power is potentially an issue in any market, and given the small number of large participants in the New Zealand electricity market, the potential for the use and abuse of market power almost certainly already exists. Despite a number of dry year events and a similar number of investigations by a number of parties, no market participant has yet been proven to have abused market power over a sustained period, let alone in a way which is deleterious to the efficient operation of the market. The EC's proposal, though light on detail, also includes a requirement for enhanced market monitoring in respect of FTRs. Though concerns remain, unless FTRs can be shown to increase the incentives around market power to a high degree, there seems no reason why they should not be introduced in the form proposed.