Application of FTRs to Hedging Strategy

Part 2: Technical Report

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with the assistance of

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Definitions

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

Aggregate location factor	The location factor used in adjusting hedge quantity to optimise hedging strategy without FTRs.
Basis Swap	Created by the sale and purchase of two futures contracts at different nodes for the same hedging period, a basis swap has a payout equivalent to an obligation FTR
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EC	Electricity Commission (to be superseded by the Electricity Authority from October 2010)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
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
WKM	Whakamaru 220 kV node WKM2201 at Whakamaru on the Waikato River.

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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[1] 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 contained in this report.

[1] A number of design issues are left to be determined once the design concept is confirmed.

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[2] (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 2) provides full details of the proposal and of how the proposed LPR hedges could be included in a hedging strategy.

Part 1 is a summary report which includes summary details of the proposal, and a series of worked examples showing how LPR hedges would be applied to hedging strategy.

At the core of New Zealand's electricity market is the spot market, through which virtually all generation and consumption is transacted at the wholesale level. At the physical level, the spot market involves transmission across the transmission grid, which results in financial transactions across the grid.

Spot prices are produced through the interaction of supply and demand on a half hourly basis, but are also impacted by imperfections in the transmission grid, and the need to ensure security: a spot pricing system known as nodal pricing in this country, or more generally as location marginal pricing (LMP). Being imperfect, the grid introduces pricing separations across the grid that are a function of transmission losses, congestion on the grid (constraints) and the requirement to provide instantaneous reserves in the island receiving power from the HVDC link.

Price separations create differences between the prices at which energy is bought and sold, and because price separations can be unpredictable, they introduce a substantial element of risk which must be assessed, mitigated or otherwise managed by participants in the wholesale market: this risk has become known as LPR~~-~~. The development of hedging instruments expressly for the purpose of mitigating LPR has been the subject of much debate since the spot market was first established in 1996.

Market participants live with LPR every day and manage it to a greater or lesser extent, with whatever tools they currently possess. But ever since the nodal market was first proposed, efforts have been made to develop formal hedging instruments for the specific purpose of assisting market participants manage their respective LPR. The long progress of the development of instruments for hedging LPR, with its many twists and turns, is beyond the scope of this report, but to cut a long story short, most of the proposals feature, to a greater or lesser extent, the use of the losses and constraint rentals left over in the spot market each month. The losses and constraint rentals are a feature of nodal pricing. The rentals grow in magnitude as price separations increase, thus they are seen to form a natural hedge against LPR.

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

The latest proposal from the EC features a formal LPR hedging instrument designed to hedge LPR between the North and South islands (a financial transmission right or FTR), along with changes to the way that the losses and constraint rentals are distributed within the industry.

This report:

1. defines the overall objectives of the development of LPR hedges from the perspective of the market participants who face LPR, and identifies the stakeholders, including market participants, but also others who may be affected to some degree by the introduction, or the lack or, LPR hedging instruments (section 2);
2. briefly reviews the FTR and other LPR hedging options and underlying theory as proposed by the Electricity Commission(EC), with reference to international experience in FTRs (section 3);
3. reviews proposals around the new electricity hedge market and develops base assumptions on what type of hedging instruments will become available in the wider market for electricity hedges (section 3.2, in particular);
4. presents brief case studies for each class of stakeholder that help to (section 5):
    a. identify risks (magnitude and impact on gross profit) of LPR;
    b. identify (and quantify where possible) the generic value of LPR hedging instruments to the stakeholders;
    c. illustrate or propose how each stakeholder would augment their existing hedging strategies with the proposed LPR hedging instruments and contrast this to implementation without these hedges;
    d. identify the tools, data, skills and other resources required to work with LPR hedging instruments;
    e. quantify where possible the difference that LPR hedging instruments would make to the stakeholders' respective businesses.
5. comment briefly on the EC's LPR hedging proposal (section 6).

In the course of preparing this report we also conducted brief phone interviews with selected stakeholders to establish the general level of understanding of the EC's proposals for location factor hedging and confirm or augment assumptions and conclusions around stakeholders' objectives. A summary of stakeholders' comments appears in section 4.

Part 1, the summary report, effectively summarises this Part 2.

2 What is the LPR Problem?

Un-hedged LPR arises in the New Zealand electricity market for four reasons, in the following logical sequence:

1. the market rules require that all generation is sold into the spot market and all electricity for consumption is purchased from the spot market: no one participating at some level in the spot market can avoid exposure to spot prices;
2. prices in the spot market are set on the basis of nodal pricing, which creates price differences across the grid, and sometimes these are substantial and unpredictable;

3. all sales into, and purchases from, the spot market are transacted at the spot price at the node on the grid at which the physical injection or off-take actually occurs;
4. market participants are not always able to obtain cost-effective hedges at the node(s) at which they have spot exposure.

As a result, we can define five potential scenarios which create some degree of LPR, relating to an independent retailer[3], large consumer, merchant generator[4], gentailer[5], or financial intermediary. Of these five scenarios, four already exist, but the fifth scenario does not, as there are currently no intermediaries offering hedging instruments in New Zealand. However, financial intermediaries are likely to enter the New Zealand hedge market as liquidity develops in the futures market due to changes required under the electricity reform bill currently in the final stages of progress through Parliament.

2.1 Independent Retailer

A retailer, by definition, supplies electricity to an electricity consumer, or to another retailer. There are examples of retailers who purchase from another retailer at a price which is independent of spot price, but in this case the retailer would not be considered truly independent of other market participants.

Of interest in this report is the independent retailer who purchases from the spot market to supply its contracted customers (consumers) at fixed prices[6]. 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 1: Independent Retailer Exposure to LPR

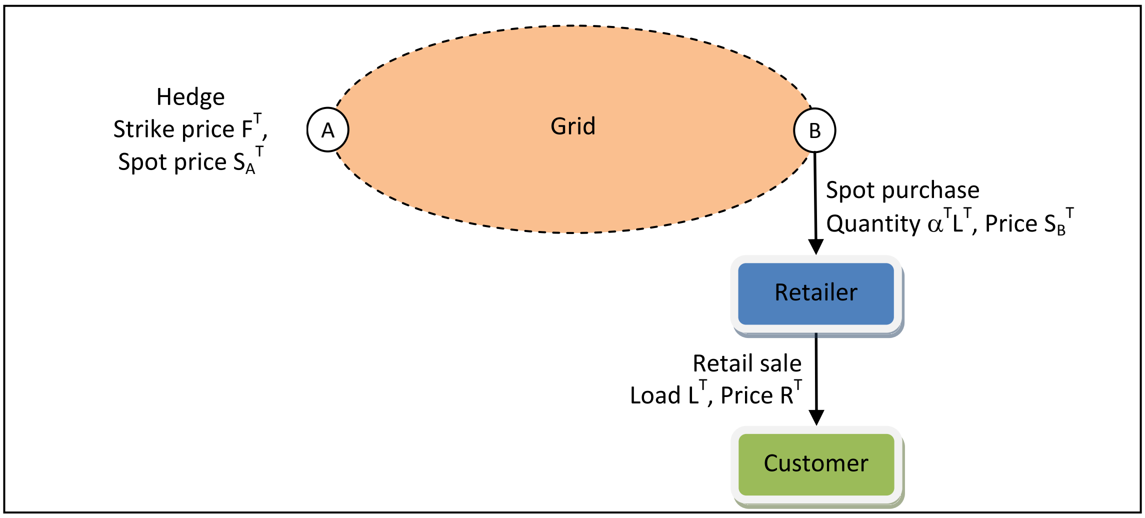


Figure 1 shows an independent retailer with FPVV customers at node B representing total metered load at time T, of L^T. These customers are supplied at fixed price R^T but to supply these customers the retailer must purchase a larger quantity, $\alpha^T L^T$ MWh at

[3] A retailer without any generation.
[4] Also known as an independent generator: a generator without any retail load.
[5] A market participant with both generation and retail load.
[6] A retailer who only ever bought at spot price from the spot market and on-sold to its customers at spot price would not be exposed to LPR.

spot price S_B^T at node B, where α^T is an adjustment accounting for losses incurred between node B and customers' meters[7].

The following equation shows the gross profit earned from a single trading period, where we ignore fixed costs and non-energy variable costs:

2-1: $$GrossProfit = L^T R^T - \alpha^T L^T S_B^T = L^T (R^T - \alpha^T S_B^T)$$

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

For the sake of convenience we now drop the time index, T, and assume that all equations relate to a particular half hourly trading period.

The arrangement above has a significant element of price risk associated with it[8], but no LPR. 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:

2-2: $$GrossProfit = L(R - \alpha S_B) - Q(F - S_A)$$

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 rearrange (2-2) to give

2-3: $$GrossProfit = LR - QF - (\alpha L S_B - Q S_A)$$

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

As shown in section 7.2, even without any instruments available specifically to hedge LPR, the optimum value of Q can be chosen based on the aggregate location factor

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

[8] The loss-adjusted spot price will at times exceed the retail price.

expected between nodes B and A, either on a deterministic basis or allowing for uncertainty.

For example, to achieve a 100% hedge on a deterministic basis (assuming we can predict the aggregate location factor accurately in advance) then we would choose Q equal to $\alpha\ell E[L]$ where ℓ is the expected aggregate location factor between the two nodes, calculated in accordance with equation 7-10 in Appendix A, and E[L] is the expected load over the period of interest. To achieve a 100% hedge taking account of uncertainty in location factor then ℓ would be calculated in accordance with (7-17). This location factor adjustment, made to the hedge quantity, is required to optimise the hedge quantity but it does not constitute a full hedge against LPR.

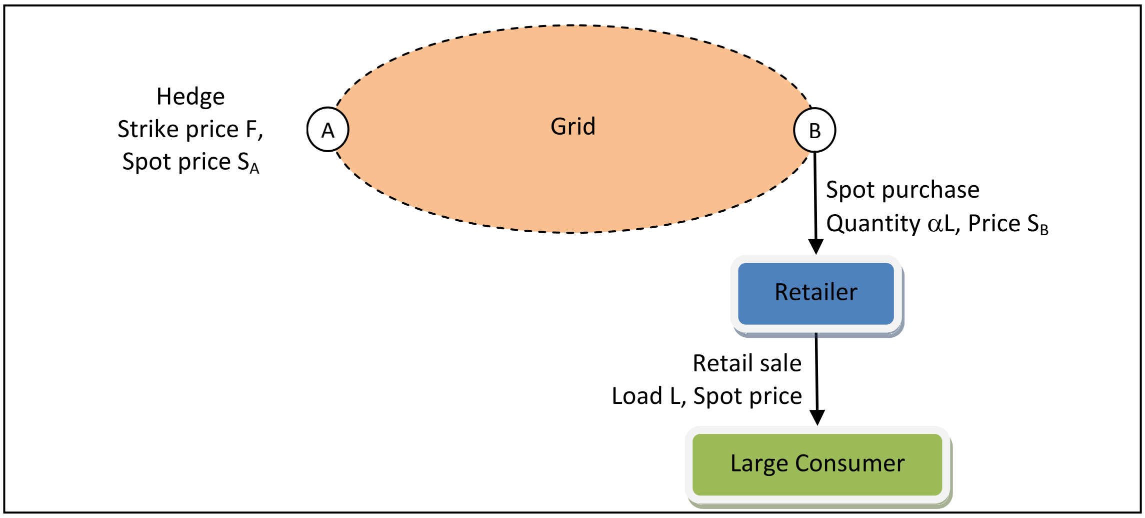
But if LPR hedges are available then the location factor adjustment may not be required, as discussed in section 5.1.

2.2 Large Consumer

A typical purchasing arrangement for a large consumer "on spot" is shown in Figure 2, 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 2: Large Consumer Exposure to LPR



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

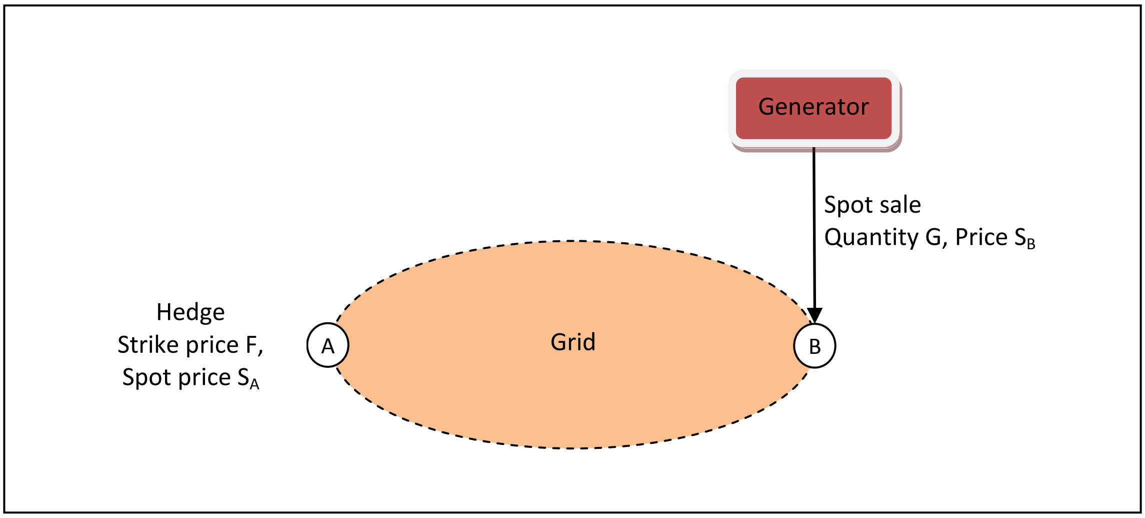
2-4: $$Cost = \alpha LS_B + Q(F - S_A)$$

and LPR arises from $\alpha LS_B - QS_A$. The hedge quantity can be adjusted along the lines given in section 7.2 to achieve a 100% hedge, but LPR remains.

2.3 Merchant Generator

Figure 3 shows a merchant generator injecting at node B and receiving spot revenue from injection G. The 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 3: 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 which case their total revenue is given by:

2-5: $$Revenue = GS_B + Q(F - S_A)$$

In this case the LPR is a function of the exposure to the price difference between the two nodes, i.e. the terms $GS_B - QS_A$ in the following equation:

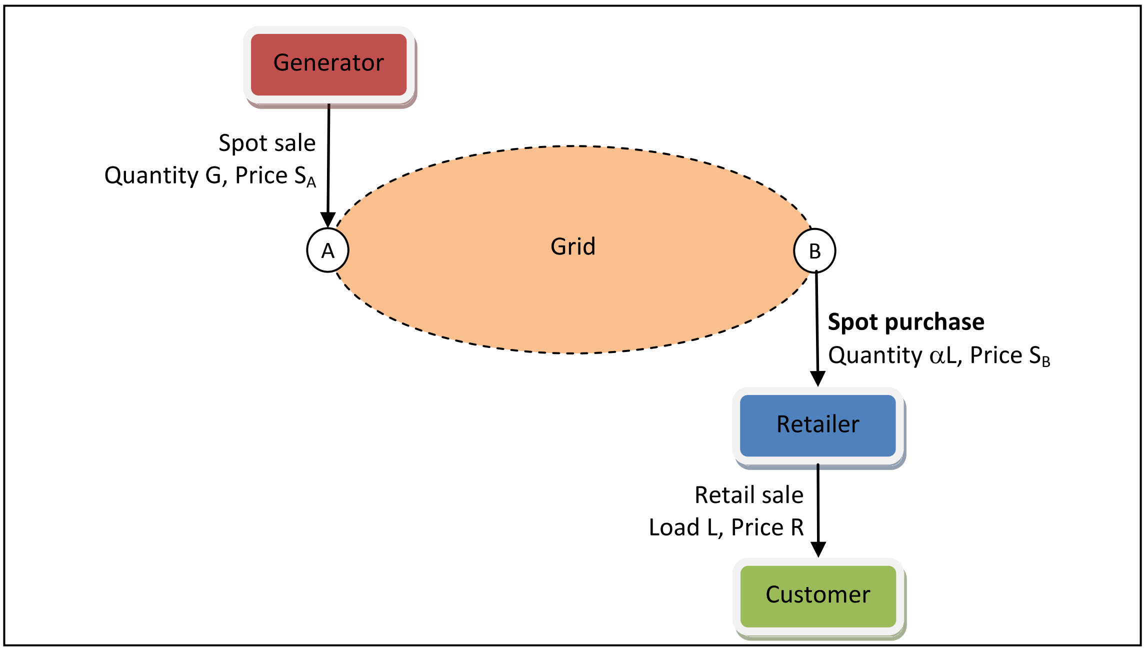
2-6: $$Revenue = QF + GS_B - QS_A$$

In the absence of any LPR hedges, a location factor adjustment should be applied to the hedge quantity, Q, to obtain a hedge ratio of 100%, but this still leaves the generator with LPR.

2.4 Gentailer

A gentailer combines the functions of both a generator and retailer as shown in Figure 4 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 4: Gentailer Exposure to LPR



Ignoring the marginal costs of generation, the gentailer's revenue is given by:

2-7: $$Revenue = LR + GS_A - \alpha LS_B$$

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, thus reducing LPR:

2-8: $$G = \alpha L \frac{S_B}{S_A}$$

which is to say that generation should be set equal to the loss-adjusted retail load multiplied by the location factor of node B relative node A. This would achieve fixed gross profit equal to LR in each trading period. But in fact it might be possible to generate more and achieve an even greater profit. 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.

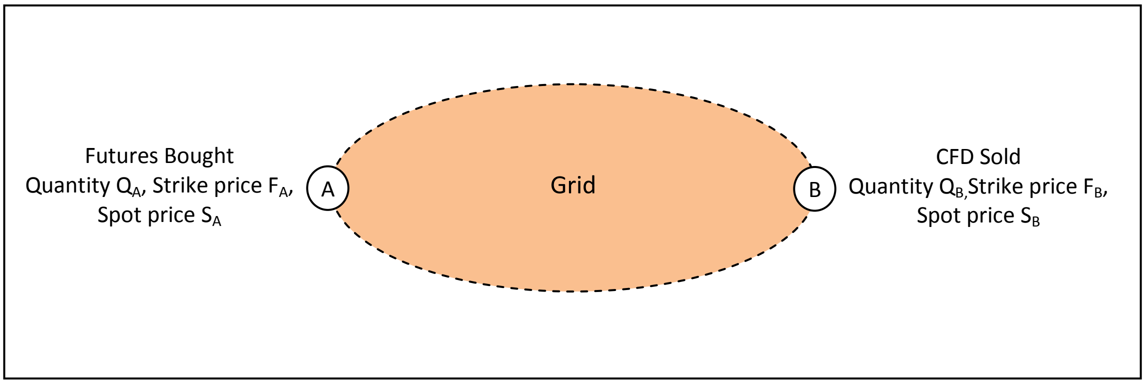
Constraints on the grid or limitations in the generator's capabilities, however, may prevent G being set sufficiently close to the ideal shown in (2-8), leading to an impaired ability to minimise LPR.

2.5 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 is likely to change this. The experience in Australia is that financial intermediaries have entered the market to intermediate 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 5.

Figure 5: Financial Intermediary Exposure to LPR



In Figure 5 the intermediary's total hedge settlements are given by

2-9: $$Q_B(F_B - S_B) - Q_A(F_A - S_A) = Q_B F_B - Q_A F_A + Q_A S_A - Q_B S_B$$

which indicates LPR arising from $Q_A S_A - Q_B S_B$. All other things being equal, the arguments relating to location factor adjustments in earlier sections would apply, and suggest adjusting Q_A to account for the expected location factor between nodes A and B. But LPR remains because the location factor may be volatile and unpredictable.

3 What are the Solutions to LPR?

The issue of LPR hedging has been debated over the last fourteen years of operation of the spot market, with various solutions proposed along the way, but this report focuses only on solutions that are either in use now, contained in the latest available proposal from the EC, or which may become available as the electricity futures market develops liquidity.

3.1 Latest LPR Proposal

The EC has proposed a solution with two key elements:

1. FTRs available for auction between the North and South islands;
2. lines companies would be encouraged to distribute residual losses and constraint rentals, plus FTR auction rentals they receive, to retailers.

[9] In the OTC hedge market, hedges are traded directly between the parties to the hedge, as opposed to futures which are traded through an organised and regulated exchange.

3.1.1 FTRs

An FTR is simply a financial instrument that entitles its holder to a share of the losses and constraint rentals.

FTRs (or their equivalent) are available in a number of LMP markets in the US including PJM[10], California, Texas, New England, New York and the Midwest, and in Australia. In the US, FTRs are considered to be a more or less standard component of an integrated and fully functioning LMP market design, albeit with residual concerns about the ability of market participants to exercise market power in the presence of transmission constraints.

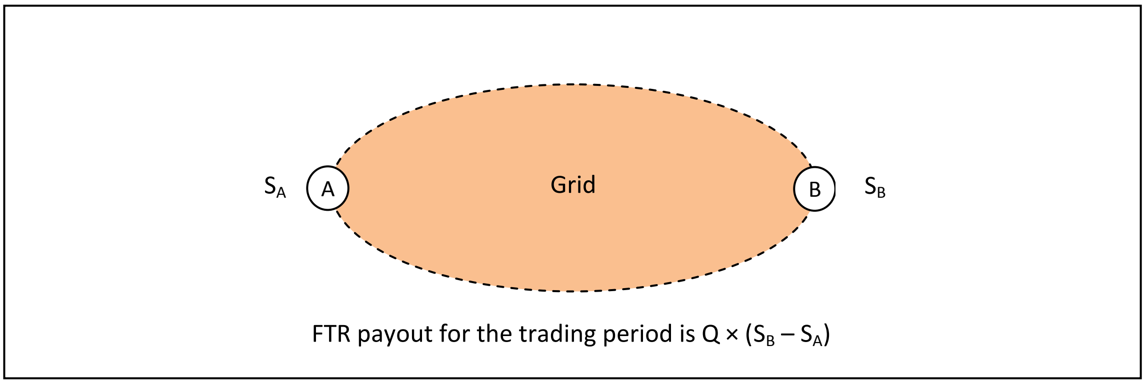
The EC's FTRs will come in two forms, an obligation FTR and an option FTR, and these will be available for hedging LPR between the North and South islands[11].

In its simplest form, an obligation FTR is a financial instrument with cash payout proportional to the difference between two spot prices at nodes A and B:

3-1: $$Payout = Q(S_B - S_A)$$

where Q is the quantity, as shown in the following figure. Assuming that S_B is greater than S_A, the holder of the FTR receives a cash payment which offsets the price risk between nodes B and A. A key feature of FTRs is that the cash payment comes, not from a hedge counter-party, but from the losses and constraint rentals generated in the spot market each month. The FTR is said to be 'fully funded' by the rentals.

Figure 6: FTR Payout



For example, consider the case of a financial intermediary hedged at two nodes distant on the grid, with settlements given by (2-9). If we simply set $Q_A = Q_B$ and add an FTR then the settlements become

3-2: $$Q_B F_B - Q_B F_A - Q_B(S_B - S_A) + Q_B(S_B - S_A)$$

10 Pennsylvania, New Jersey, Maryland.
11 Having only an inter-island FTR means that new hedging opportunities will be limited within each island, but the EC does state that other hubs may be added over time if there is demand from FTR purchasers.

which reduces to $Q_B(F_A – F_A)$. This has achieved two things:

1. LPR has been eliminated; and
2. the selection of Q_B (the quantity of the hedge purchased to offset the risk of the original hedge sale at nodeB) has been simplified: it is simply the same as the original hedge's quantity, and there is no need to consider any form of location factor adjustment to the hedge quantity at node A.

This example illustrates the conceptual simplicity and elegance of FTRs. There is one catch, however, and that is that the FTR comes at a cost: the EC's proposal is that FTRs will be not be available for free, but will be auctioned[12]. This will require the FTR purchaser (the intermediary in this case) to price the FTRs on offer by placing a value on the expected price differences between nodes A and B (refer to section in 7.3 Appendix A): this means that when FTRs are available, would-be FTR purchasers will have to make an assessment of the expected price difference between A and B, just as they do now in making a location factor adjustment to the hedge quantity.

Notwithstanding the need for analysis of price differences or location factors, one point must be emphasised: the primary advantage of the FTR is that it can eliminate LPR, whereas the location factor adjustment only reduces the impact of LPR.

The obligation FTR described above references the spot prices at two nodes. The proposed FTRs are a little more complicated: they will reference virtual spot prices known as "hub prices". There will be a hub in each island and its price in each trading period will be an average of all prices in the island, weighted by generation: this is known as a "GWAP hub price".

While the GWAP hubs have the disadvantage of not mapping directly to a node, they have the advantage that all GIPs in an island will contribute to the hub price. But either way, most FTR purchasers will be left with some residual LPR which will need to be assessed and managed.

Thus far, we have implicitly assumed that the holder of an FTR between nodes A and B would always receive a cash payout because the spot price at B would always be higher than the spot price at A. However, this may not always be the case, particularly as inter-island power flows have long periods when they predominate in one direction or the other. In addition to obligation FTRs, therefore, the EC proposes to offer option FTRs which would payout only when the price difference between the islands is in the FTR purchaser's favour. These would be attractive to parties whose LPR is primarily associated with flows in one particular direction between the islands, e.g. the LPR might only be associated with dry years when high southward flows are likely (resulting in average South Island prices being higher than average North Island prices).

As a result of this optionality, option FTRs would most likely command a premium at auction relative to obligation FTRs.

[12] This raises an interesting question: why is that FTRs will have a direct cost, when CFDs and futures do not? The answer is that an FTR is a not contract between two parties who wish to hedge their respective spot price risk. Instead, it is a contract giving the FTR purchaser the right to receive cash payouts from the losses and constraints rentals, an amount of money which is 'owned' by the market itself (and the market has no price risk to hedge). Various forms of completely free allocation of FTRs and the rentals themselves have been investigated over the years, but rejected.

3.1.2 Distribution of Losses and Constraint Rentals

Ever since the spot market commenced in October 1996 the monthly losses and constraint rentals have been paid to Transpower who currently distribute the total rentals to its customers who pay transmission charges.

Transpower has an internal process which separates rentals relating to:

1. connection assets: this is a small percentage of total rentals relating primarily to rentals generated in transformers at substations at which customers connect (connection rentals)[13];
2. the rentals generated on the HVDC link (DC rentals);
3. all other rentals (AC rentals).

Connection rentals are allocated to customers paying for the relevant connection assets.

AC rentals are allocated to lines companies and direct-connect[14] consumers who pay transmission charges relating to the AC transmission grid in proportion to their payment of the Transpower interconnection charge: the proportion is based on the customer's demand which is coincident with peaks in the grid. Some lines companies currently distribute their rentals revenues to retailers who have customers on their distribution network, on a voluntary basis.

DC rentals are allocated to south island generators who pay HVDC charges[15] in proportion to their historical maximum injection at South Island GIPs.

Under the EC's proposal there would be two pools of money available each month to distribute in place of the total pool of rentals:

- income from auction of FTRs: for example if FTRs are auctioned this month for the coming year, then the auction revenue received this month would be distributed this month;
- the rentals left over ("residual rentals") after paying out on any and all FTRs which had previously been purchased and which related to spot prices set in the current month: for example, if a party has an FTR relating to October 2013, then it would be paid from rentals left over in the spot market in November 2013 after all spot market sales and purchases are settled.

The EC's proposal is to distribute this total pool consisting of FTR auction proceeds and residual rentals to parties paying transmission charges in proportion to their share of total transmission charges. The groups receiving these distributions would include generators, South Island generators, lines companies and direct-connect consumers.

In addition, lines companies would be "encouraged" to pass their rentals and auction income to retailers operating in their respective distribution networks, in proportion to the retailers' respective off-takes. If all lines companies pass rentals through to

[13] This pool of rentals includes any lines that are also classed as connection assets.

[14] There are currently seven direct-connect consumers.

[15] Embedded generation which causes injection onto the grid in the South Island actually creates an obligation on the relevant lines company to pay HVDC charges, which in turn would trigger an allocation of DC rentals back to the lines company. In practice, HVDC charges (and perhaps DC rentals) are passed through to the generator concerned by the lines company.

retailers, then retailers would uniformly receive the benefit of distributions of auction income and residual rentals.

3.1.3 Summary of Proposal

In summary, the EC proposes to make inter-island FTRs available which reference island GWAP hub prices, and which would be available as obligation FTRs and option FTRs. FTRs would be auctioned off to the highest bidders, and the auction proceeds distributed to parties paying transmission charges. Each month the losses and constraint rentals would be used to make FTR payouts, and the residual rentals left over from this process also distributed to parties paying transmission charges. Lines companies would be encouraged to allocate their residual rentals and auction revenues to retailers with 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 constraint rentals[16].
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 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.
FTR specifications	Two products available - base-load and peak[17]: • 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

[16] Ensuring FTRs are not oversold requires an analysis of "revenue adequacy" to be undertaken at auction time.
[17] 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.

Design Element	Description
	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.

3.2 New Futures Market

A key recommendation of the Ministerial Review of the electricity market undertaken in 2009 was to reform the hedge market through establishment of a liquid electricity futures market for New Zealand. This development has potentially far-reaching implications for the hedge market and potentially for hedging LPR.

The futures market was established in July 2009 and is run by the Australian securities market operator, ASX, and initially features contracts at two nodes, Otahuhu (OTA) and Benmore (BEN), though other nodes may be added if there is the demand. The five largest gentailers are required to be 'market-makers' which is to say that they will be required to simultaneously offer to buy and sell futures contracts in quantities which are large enough to create a an initial degree of liquidity. For the purposes of the hedge market reforms, the initial liquidity requirement is defined as having 3,000 GWh of unsettled futures contract in the market by June 2011[18]. Whether or not this benchmark is achieved, or whether liquidity will develop beyond this level, only time will tell.

Liquidity in the futures market introduces the possibility of being able to create[19] what are commonly called "basis swaps" using futures contracts. Basis swaps are not the same as FTRs because they are not funded from the losses and constraint rentals, but they can be constructed to have the same payout as obligation FTRs[20]. This introduces the possibility of using basis swaps to value FTRs and vice versa. The availability of both FTRs and basis swaps also increases the range of complimentary LPR hedging alternatives available in the market, and potentially will provide further stimulus to the demand for LPR hedges.

The futures contracts are effectively configured as a base-load CFD covering an entire quarter with quantity of 1 MW (Q = 0.5 MWh per trading period)[21]. CFDs are settled in the month immediately following the month they actually relate to, but futures are subject to daily settlement, which is to say that the change in their value is calculated every business day by reference to the futures price.

For example, suppose that on 1 June 2012 a generator sells a futures contract covering the quarter ending 31 June 2014 and its strike price is $100/MWh. If on the next

[18] For further commentary see this post on the Energy Link blog.
[19] An LPR hedge using futures or CFDs might be created deliberately, or it might come about unintentionally in the normal course of hedging spot exposure around the grid.
[20] The ASX also has electricity options for New Zealand, which offer the potential to create basis swaps with payout similar to option FTRs.
[21] The futures contracts are actually specified as CFDs which reference the average spot price at the node for the quarter concerned.

business day the price of these contracts has fallen to \$99/MWh then the contract has gained in value by \$1/MWh for every MWh covered by the contract, and the generator receives an amount of cash equal to \$1 multiplied by the total quantity of the contract. The total volume of a 1 MW futures contract for this quarter of 91 days duration is 1 MW × 91 days × 24 hours = 2,184 MWh. Hence the increase in the contract's value is \$2,184 and this amount is credited to the generator's account with the futures broker responsible for settling the contract.

If daily settlement works in the other direction (in this example the futures price would be going up) then there may come a time when accumulated daily settlements have emptied the generator's account below a pre-defined minimum balance (known as the 'maintenance margin'), in which case the broker issues a 'margin call' which requires the generator to bring their account up to the 'initial margin' (which is actually somewhat higher than the maintenance margin.)

Suppose that we buy and sell futures contracts at two different nodes, for example OTA and BEN:

$$Cashflow = Q(F_{OTA} - S_{OTA}) - Q(F_{BEN} - S_{BEN})$$

which can be rearranged to give

3-3: $$Cashflow = Q(F_{OTA} - F_{BEN}) - Q(S_{OTA} - S_{BEN})$$

The second half of the equation above is $Q(S_{OTA} - S_{BEN})$ which has the same form, and same net payout, as the FTR we are now familiar with from section 3.1.1. The first half of the equation is $Q(F_{OTA} - F_{BEN})$ which is a fixed quantity (since all three parameters Q, F_{OTA} and F_{BEN} are fixed) and can be thought of as the cost of the basis swap created in this way, analogous to the cost of purchasing an FTR at auction.

As the futures market develops liquidity and attracts new participants, for example financial intermediaries that already trade on the Australian electricity futures market, then liquidity could increase in the CFD market. An intermediary would buy or sell a CFD and then either sell or buy, respectively, a futures contract to offset the risk of the CFD. To make money on this hedge market dealing, the intermediary might introduce a small margin (also known as a 'spread') between the CFD strike price and the corresponding futures strike price[22].

In this case there will also be the possibility to create a basis swap using CFDs, even if this comes with a slightly higher cost in terms of $F_{OTA} - F_{BEN}$ in the equation above (arising due to the spread between the futures and CFD strike prices).

Comparison of equation 3-3 with 7-2 shows that the two approaches to hedging LPR, FTR or basis swap using CFDs or futures, have equivalent payouts if the following two conditions are met: firstly, that the FTR is written between OTA and BEN; secondly, that equation 3-4 holds.

[22] Although the futures price may be lower or higher than the corresponding CFD price, there are direct and indirect costs to dealing the futures market which are not faced in the OTC hedge market. The spread therefore covers those costs which the intermediary faces, plus some profit margin.

3-4: $Q(F_{OTA} - F_{BEN}) = FTRCost$

The FTRs proposed by the EC actually refer to the island GWAP hub prices, so one of these two conditions does not hold. Nevertheless, (3-4) suggests that the value of the proposed FTRs should be closely linked to price differences observed in the futures market, after allowing for a location factor difference between futures nodes and GWAP hubs. This will assist FTR purchasers price FTRs prior to auction, and value FTRs they already own. It also offers an additional way of hedging LPR: section 6 discusses the pros and cons of hedging LPR with FTRs and basis swaps.

Let us loosely define the "futures weighted average price" in the North Island (FWAP) as the generation-weighted average futures price in the North Island: for any given quarter the FWAP would equal a weighted average of the futures prices at all nodes in an island at which futures contracts are traded (currently this is just OTA).

If we also write $FTRCost = Q \times FTRPrice$ then 3-4 tells us that

3-5: $FTRPrice \approx FWAP - F_{BEN}$

which suggests that the proposed obligation FTRs could be priced and valued by reference to the futures market.

But there may be good reasons why 3-5 does not hold. For example, FTRs may only be available in limited supply relative to futures contracts, or may not ultimately be tradable, or may have different minimum quantities, or there may be market power issues which apply to FTRs but not to the same extent to futures contracts.

3.3 Existing Hedge Market

Some market participants tell us they already have an ability to obtain hedge cover in regions where they have un-hedged spot exposure or otherwise have some form of LPR. The existing OTC hedge market (which currently does not have financial intermediaries as participants) remains a possible source of hedges for managing LPR, but with the introduction of FTRs, the development of liquidity in the futures market, and the entry of intermediaries into the OTC market, one would expect the use of other hedges for hedging LPR to reduce over time.

3.4 Losses and Constraint Rentals

Market participants currently receive rentals each month if they are South Island generators or if they are retailers with customers connected to distribution networks where lines companies pass rentals revenue to retailers. Direct-connect consumers also receive rentals direct from Transpower in the same way as lines companies.

Market participants and direct-connect consumers tell us that they view these rental allocations as partial hedges against LPR. The hedging impact of HVDC rentals for South Island generators may be quite significant, given that proportionately the HVDC link generates significant price differences and hence rentals.

However, for most retailers the LPR hedge effect is watered down by the allocation of AC rentals to lines companies based on their demand (assuming the lines companies passes the rentals on to retailers). For example, a South Island retailer affected by a large price separation event within the South Island would find the greater proportion of the additional AC rentals generated by the event distributed in the North Island where total demand is greater.

The EC's proposal would improve the situation somewhat by ensuring that AC rentals would be passed through by lines companies. Nevertheless, the effectiveness of this measure as a hedge against LPR is rather limited. Instead, its value lies in securing access to an additional source of revenue.

3.5 Regional Integration

No discussion of LPR would be complete without consideration of regional integration, which can be defined as a risk management strategy that limits LPR by retaining all generation, retail and hedges within the boundaries of a defined sub-region of the grid. Although we are not aware of any work which quantifies the relationship between LPR and separation on the grid, it is given a priori that LPR increases with distance on the grid.

Regional integration is a driver of vertical integration in general[23] but it is not the only driver. For example, gentailers also view a large and growing retail customer base as a long term hedge in respect of new generation they intend to build.

Market participants, especially smaller players, tell us that regional integration remains a part of their strategy, whether or not FTRs are introduced. In the longer term, however, changes in the market may cause participants to reduce their emphasis on regional integration. Competition has increased significantly in the retail market in the last two years, making it more difficult and more expensive to grow retail customer bases. If generators become confident of sustained liquidity in the futures market, and have effective hedges against LPR, then the alternative to attracting more retail customers as a hedge against the risks associated with new plant, is to hedge that risk using combinations of FTRs, futures and OTC hedges.

3.6 Location Factor Adjustments

In the five scenarios outlined in section 2 we noted that, without some form of explicit LPR hedge, a location factor adjustment should be made to hedge quantities in order to achieve a 100% hedge. This adjustment cannot be considered to hedge LPR in the same way as an FTR, for example, but it nevertheless achieves a partial hedge because it reduces the residual hedging risks relative to a hedging strategy which did not make the location factor adjustment[24], especially when the expected location factor is significantly different to one.

In fact, there are many instances where the location factor adjusted hedge strategy works well. The EC's proposal only covers inter-island LPR so location factor

[23] New Zealand's is vertically integrated to the tune of 80%.
[24] Such a strategy would simply use quantity at the node of the spot exposure as the hedge quantity at the distant node.

adjustments, as fully described in Appendix A, will remain a key part of hedging strategy to manage 'intra-island LPR'[25].

4 Market Participant's Views

During the course of preparing this report, we spoke to a number of market participants (including major users) to better understand what issues they have in respect of the application of LPR hedges in their hedging strategies.

We gained the impression that there are varying levels of enthusiasm for FTRs in some quarters. Some participants either felt they would not use FTRs, or that other reforms were more important and that FTRs should be revisited later, while others felt they would make use of FTRs.

There was, however, more widespread support for the pass-through to retailers, by lines companies, of residual rentals and FTR auction income.

Comments were many and varied, but in terms of application to hedging strategy, three themes came through, though not consistently across all participants:

- FTRs are complex and will require additional resource in order to make use of them;
- FTRs between island GWAPs will do nothing to hedge LPR within each island;
- the extent that FTRs will change the incentives to use market power is of concern.

The tools and resources required to evaluate and make use of FTRs turn out not to be much different to those in use already by market participants to evaluate price risk, as briefly outlined in section 5.11. As FTRs become available we expect that market participants will, over time, adapt their existing hedging strategies to make good use of them, perhaps along the lines described in this report (including in Part 1).

Work undertaken by Energy Link and the EC, show that inter-island LPR is a much bigger issue than intra-island LPR. LPR within each island is a concern to particular participants from time to time, however the formulae in this report and the worked examples in Part 1, show that managing intra-island LPR using FTRs goes most of the way to eliminating LPR. Once the infrastructure required to support inter-island FTRs is available, intra-island FTRs will be relatively simple to introduce.

Market power is recognised as an issue by the EC, hence the EC's proposal includes a requirement to monitor the use or abuse of market power in respect of FTRs. This is discussed further in section 5.15.

5 Application to Hedging Strategy

This section discusses how market participants might integrate the proposed FTRs into their respective hedging strategies and also reviews the way that FTRs would be purchased, valued and settled. It also discusses other important issues including whether the settlements are guaranteed and how FTR cash flows impact on market participants.

[25] LPR present by virtue of price differences between nodes within an island or between a node in an island and the island GWAP hub.

The scenarios developed in the following sections include formulae derived based on three key assumptions:

1. the market participant is considering one or two spot exposures in isolation (other nodes and instruments which give spot exposures are not considered);
2. the market participant wishes to achieve 100% hedge on average;
3. that residual risks are insignificant, in particular that residual risks associated with spot volumes[26] are insignificant in the context of hedging strategy.

Worked examples and further analysis are contained in *Application of FTRs to Hedging Strategy, Part 1: Summary Report.*

For many market participants these assumptions will not all be valid, and hedging strategy will needed to be customised accordingly.

Readers are also reminded that the information and formulae in the following sections are of a general nature and are provided to inform, educate and assist the wider debate on LPR hedging. 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 stress tested (tested against a wide range of adverse scenarios before it is implemented).

5.1 Independent Retailer

In section 2.1 we developed the scenario of an independent retailer hedging its retail load at node B, at a distant node A, and we identified LPR of αLS_B - QS_A where αL is the retail load at node B multiplied by the local loss factor.

If it were possible to purchase an FTR between nodes A and B then the retailer's optimum hedging strategy would be accomplished in two steps:

1. purchase a hedge at Node A with quantity $E[\alpha L]$, which is the expected value of the loss-adjusted load[27]; and
2. purchase an FTR between nodes A and B with quantity of $E[\alpha L]$.

Adding this FTR to the gross profit shown in equation 2-3 ensures that the gross profit becomes

5-1: $$GrossProfit = LR - E[\alpha L]F$$

which now contains only one variable that is not fixed in advance, i.e. L (the retailer's load at node A) and so the gross profit is now free of LPR. The fully hedged gross profit is a function of retail revenue (load, L, multiplied by retail price, R) and the hedged spot purchase cost ($E[\alpha L]F$).

[26] As opposed to the risks associated with volatile spot prices. Volume risks include the risk that generation, retail load or load will not turn out as expected during the hedging period under consideration.
[27] If the retailer is confident the loss factor will not change over time then the quantity is $\alpha E[L]$.

We must be careful not to forget that the FTR came at a cost, FTRCost (refer equation 7-2), when the FTR was purchased at auction. But the key point to note here is that a volatile LPR created by virtue of exposure to the difference between two spot prices, has been replaced by FTRCost which is fixed at auction time.

But the EC's proposal is only for inter-island hedging between island GWAP hubs, so equation 5-1 is not usually going to hold exactly. If nodes A and B are in the same island then the EC's proposed FTRs do not have any application in hedging strategy. If A and B are in different islands, however, then we add an FTR $Q(H_B – H_A)$ where H_B is the hub price in the same island as node B, and H_A the hub price in the same island as node A. In this case the gross profit is given by

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

Following the approach outlined in section 7.5 we set $Q = Q_{FTR}$ so that we have the hedge and the FTR with the same quantity, Q. Then a 100% hedge is obtained when we use the result of equation 7-26 and set

5-2: $$\frac{Q}{\overline{\alpha L}} = \frac{\hat{S}_B}{\overline{H}_B + \overline{S}_A - \overline{H}_A}$$

where $\overline{\alpha L}$ 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, and the $\overline{S}_A$, $\overline{H}_A$ and $\overline{H}_B$ are the time-weighted average prices at node A, hub A and hub B, respectively. To make life simpler, in many applications we can also use $\overline{S}_B$ instead of $\hat{S}_B$, i.e. where q is approximately constant over the hedging period being considered.

In practice, the choice of parameters in (5-2) would be based on forecasts of each parameter, i.e. the parameters would be the expected values in each case.

5.2 Large Consumer

The large consumer scenario developed in section 2.2 requires purchase of an FTR $Q(H_B – H_A)$ and has the solution for Q given in equation 5-2 in the previous section.

5.3 Merchant Generator

The merchant generator scenario developed in section 2.3 has a similar solution but this time the generator must purchase the FTR $Q(H_A – H_B)$ which is to say that the FTR payout is in the opposite direction to the FTR purchased by the retailer and large consumer (who are both spot purchasers). Once again, the generator's hedge and physical nodes must be in opposite islands.

Once this is done then the hedge and FTR quantity should be set equal to

5-3: $$\frac{Q}{\overline{G}} = \frac{\hat{S}_B}{\overline{H}_B + \overline{S}_A - \overline{H}_A}$$

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 5-1 and 5-2 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.

5.4 Gentailer

Referring to (2-7) in section 2.4 the gentailer has no CFDs or futures in this scenario, but does sell to customers at fixed retail price R. Their objective in respect of obtaining an FTR is to minimise their exposure to the price difference between the islands, and so they may purchase an FTR $Q(H_B – H_A)$ and so, ignoring the marginal cost of generation, their gross profit becomes

$$Gross\ profit = LR + GS_A - \alpha LS_B + Q(H_B - H_A)$$

The generator may decide to purchase an FTR with quantity equal to the loss-adjusted load, αL, and in this case minimising LPR requires solving

$$GS_A - \alpha LS_B + \alpha L(H_B - H_A) = 0$$

which has the solution

5-4: $$G = \alpha L\left(\frac{S_B + H_A - H_B}{S_A}\right)$$

The generator may be able to improve their gross profit by generating more or less than this quantity, but this is the generation that minimises LPR in respect of the gentailer's retail load.

It would be tempting at this point to assume that the gentailer can always achieve this output, but there is a pitfall in making this assumption: large price differences between the islands occur when lines are constrained, or when the HVDC link is constrained by reserves, in which case following the load may simply not be possible. The gentailer must make an assessment of the likely difference between customer load and generation in these instances, and 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.

5.5 Financial Intermediary

The financial intermediary sells a CFD to a customer at node B in one island and hedges this sale with the purchase of a futures contract in the other island at node A. They then have the payout shown in (2-9) in section 2.5. We now add an FTR with the same quantity as the CFD at B, with form $Q_B(H_B – H_A)$, which the intermediary purchases to protect themselves against volatility in the nodal price difference, and the payout becomes:

$$Q_B(F_B - S_B) - Q_A(F_A - S_A) + Q_B(H_B - H_A)$$

We can follow the method of section 7.2.1 to give a result for the quantity of hedge to purchase at A for a hedging period covering multiple trading periods:

5-5: $$\frac{Q_A}{Q_B} = \frac{\bar{S}_B + \bar{H}_A - \bar{H}_B}{\bar{S}_A}$$

which is to say that the FTR quantity is a function of the time-weighted average spot prices and hub prices.

5.6 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[28]. 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 base-load.

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

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.

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

5.6.1 Obligation versus Option FTRs

The 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 ($H_B – H_A$).

5.7 Pricing FTRs

An important consideration when bidding to purchase an FTR is the price that will be bid. Equation 7-21 shows that the FTR price per MWh of FTR quantity is the difference in the expected prices, on the assumption of risk neutrality (or, equivalently, that there is a market for FTRs traded between risk averse market participants – refer section 7.3). This 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 = $E[H_A] – E[H_B]$

If market power turns out to be an issue with FTRs, then any player who believes they may have the market power to create excess profits from FTRs, or who wishes to speculate in FTRs, could bid the price of FTRs above risk neutral levels and thus introduce a risk premium. This issue is discussed further in section 5.15.

5.8 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[29].

Auctions will be conducted monthly for each of the 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, 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.

5.8.1 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

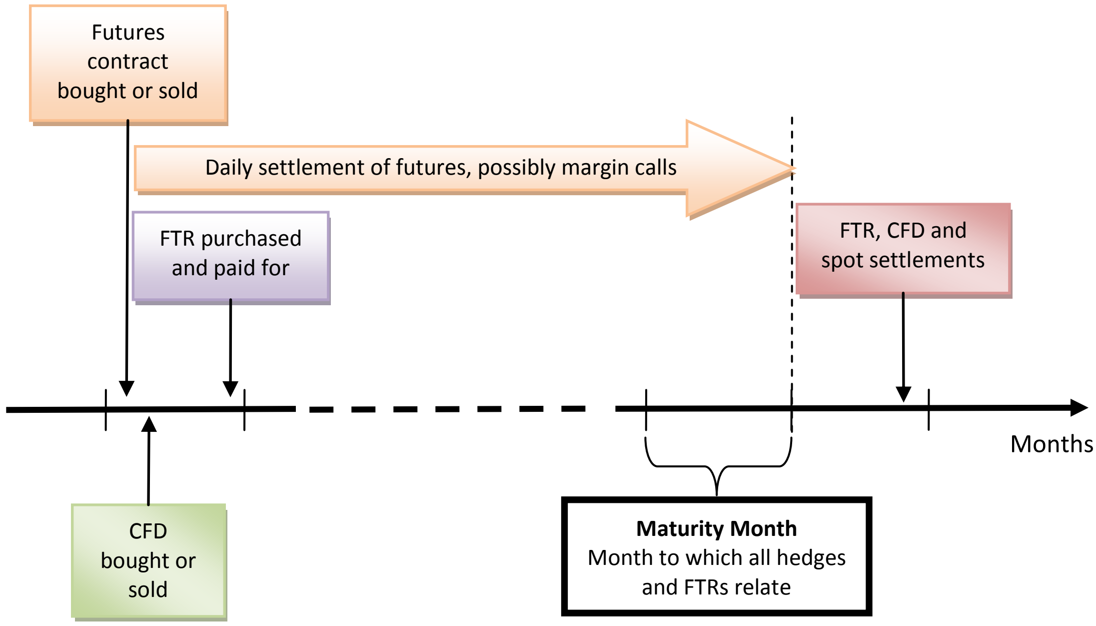
[29] This may only occur once an FTR is purchased, or it could be that a master agreement is signed, after which individual FTRs are added as transactions as they are purchased.

prudential requirements for spot purchases[30]: cash deposits, suitable credit rating, letters of credit or other instruments will be required to a level that guarantees settlement. 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.

5.9 FTR Settlements and Cash Flows

Figure 7 shows the timing of various cash flows in the market.

Figure 7: 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 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[31].

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

[30] FTR settlements will be undertaken by the Clearing Manager who also settles all spot purchases and spot sales.
[31] The futures contracts settle 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.

electricity market participants, which must be carefully considered before transacting in either instrument.

5.10 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.

5.11 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.

In section 7.3 we showed that 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.

In sections 5.1 through 5.5 we provided basic formulae which can be applied to calculate the quantity of FTR that should be purchased (or at least bid for, or whether an FTR should be traded) for any particular hedging period. These formulae 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.

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

The tools usually employed to estimate expected spot and hub prices 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.

5.12 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).

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 is 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 price 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.

5.13 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).

5.14 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.

5.15 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 competition for FTRs, leading to less than ideal FTR pricing.

The discussion in section 3.2 showed that a basis swap can be constructed from two futures (or CFD contracts), which leads to the result in 3-5 suggesting that FTRs may be able to be valued by reference to the prices of futures contracts traded at the same time and covering the same period as the FTR. A market participant with market power may bid up the price of FTRs in FTR auctions, based on their ability to influence the FTR payout. If the price of FTRs deviates significantly above the price indicated by the futures market, then this could be an indication that market power is in use[32].

Which begs the question: if basis swaps can be constructed using two futures contracts, is market power any more of an issue with FTRs than it is with the hedge market?

Although full details are not yet available, the development of the futures market requires the five major market participants to act as ‘market-makers’: they will be required to offer to sell, and bid to buy, a minimum number of futures contracts at each node in the futures market, with a maximum spread between the offer and bid prices. The minimum number of contracts that must be on offer might be referred to as the ‘depth’ of the market-making function.

A market-maker with market power could attempt, for example, to raise the price of their offers to sell futures contracts, but then the maximum spread would require they also raise the price of their bids to buy futures. If the price rises far enough then other futures sellers will execute trades at the raised buy price: this may not be in the interest of the market-maker. The market-making requirement therefore has the potential to discourage the use of market power in the futures market.

The effectiveness of the market-making requirement in limiting the use of market power depends on two factors:

- the size of the maximum spread: the smaller the spread the less the market-maker can move prices before they will be buying (or selling) at higher (or lower) prices than the market; and
- the depth of the market-making requirement: if the requirement is shallow then the market-maker may sacrifice the sale (or purchase) of a few contracts in order to move the futures price.

The existing EnergyHedge market has a market-making requirement consisting of a 10% maximum spread and a depth requirement of zero, i.e. there is no requirement to make any offers or bids on EnergyHedge. This means that EnergyHedge could be moved at least 10%, at least temporarily, above or below market with little or no risk to market-makers.

Given the drive to create liquidity in the futures market, it is reasonable to assume that the futures market-making requirements will be more stringent than they are on EnergyHedge. For example, the maximum spread could be a few percent of the average bid and offer prices, and the depth requirement could be for a minimum number of contracts to be offered for sale and purchase each month.

[32] Other factors may also be at play – refer the last paragraph of section 3.2.

If this turns out to the case, then the incentives to exercise market power will be constrained somewhat, due to the risks of selling or buying a large number of contracts at prices which are not in the interests of market-makers. The implication in respect of the proposed FTRs is that market power may be able to be observed directly in the difference between the prices of FTRs at auction, relative to the prices of basis swaps.

The use of GWAP hubs in FTRs may also reduce the incentive and ability to use market power with FTRs, simply by virtue of averaging.

But, it must be noted that if market power turns out to be an issue with FTRs, then this could lead to offer strategies which have the potential to raise or lower prices in the futures and CFD markets.

The implication for hedging strategy is that the possibility that market power could be used in respect of FTRs, could make FTRs more or less attractive as a hedging instrument than basis swaps.

But 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.

5.16 Choosing an LPR Hedge

The table in Appendix B compares various methods of hedging LPR.

6 Commentary on the EC's Proposal

The primary objective of this report is to help stakeholders understand how the proposed FTRs may be integrated into hedging strategies, but in this section we provide a brief commentary on the current proposal. Our objective is to assist in the consultation process initiated by the EC in respect of the FTR proposal.

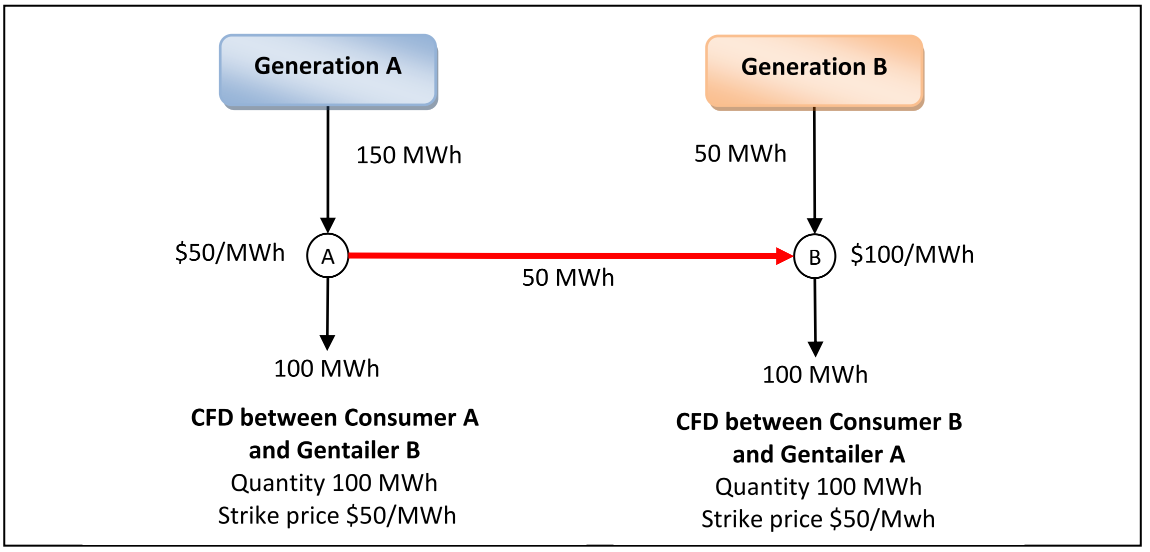
We agree that the greatest LPR exists between the islands, rather than within each island, but we have also shown that the new futures market opens up the possibility of creating basis swaps by buying and selling futures or CFD contracts at different nodes. While this has so far been raised as a possibility, it is now time to explore the implications of having access to both FTRs and basis swaps.

6.1 Comparison of FTRs and Basis Swaps

Consider the simple market shown in Figure 8 with nodes A and B in separate islands. Two gentailers A and B with generation at A and B, respectively, supply two large consumers, one at node A and one at node B. The consumers purchase energy via one or other retailer, but we ignore these spot purchases because they are a straight pass-through at spot price (and therefore introduce neither price risk nor LPR for the gentailers). However, the consumers are fully hedged with the hedges shown.

For simplicity, losses are ignored. The power flow limit of the interconnecting line is 100 MW (equivalent to 50 MWh per half hourly trading period).

Figure 8: FTR versus Futures



In the normal course of events, we assume the generation at A and B is roughly balanced with little flowing either way across the interconnecting line. The offers of the generation at A and B are usually $50/MWh but each generator has available some more expensive generation which is offered at $100/MWh.

However in the trading period shown there is an outage of the cheaper generation at B which means that more generation is dispatched at A, and more of the cheaper energy is transferred across the line up to its limit of 50 MWh per half hour: price separation of $50/MWh results.

Each of the gentailers is hedged at a distant node and so they have LPR due to the possibility of a constraint on the interconnecting line. But when the line is not constrained they each expect to earn roughly $5,000 which is based on the average of the 100 MW they each generate to supply their fully-hedged customers.

The settlements for this trading period give constraint rentals equal to the total payments by purchasers less total payments to generators:

$$Rentals = 100\times 50 + 100\times 100 - 150\times 50 - 50\times 100 = \$2{,}500$$

Revenue for the two gentailers is given by:

$$Revenue\ A(no\ FTRs) = 150\times 50 + 100\times(50-100) = \$2{,}500$$

$$Revenue\ B = 50\times 100 + 100\times(50-50) = \$5{,}000$$

Suppose that generator A wished to hedge LPR with an FTR $Q(S_B - S_A)$ and that they had purchased one with a quantity of 50 MWh. Then their revenue would have been

$$\text{Revenue } A(\text{with FTR}) = 150 \times 50 + 100 \times (50 - 100) + 50 \times (100 - 50) = \$5{,}000$$

In this case the payout on the FTR exactly equaled the rentals generated by the constrained line[33], and has brought gentailer's revenue back up to the expected $5,000. The proposed FTRs would be paid out of rentals, and in this case the rentals fully funded the FTR[34]. All other things being equal, the cost to gentailer A of purchasing the FTR should have been small because the line is not expected to constrain often, so the expected price difference between nodes A and B would be small.

Let us now assume instead, that the two gentailers traded CFDs (or futures) to create a basis swap for gentailer A: this might occur as a deliberate strategy to form a basis swap, but it might also occur unintentionally as the two gentailers look to hedge their spot exposures at the distant nodes. It involves A selling B a 50 MWh CFD with strike price F_A at node A, and B selling A a 50 MWh CFD with strike price F_B at node B. The result is that A has an additional payout given by:

$$50(F_A - S_A) - 50(F_B - S_B) = -50(F_B - F_A) + 50(S_B - S_A)$$

This includes a fixed cost of $50(F_B - F_A)$ which is effectively the cost of the basis swap (assuming S_B is expected to be slightly higher than S_A on average), and the basis swap itself, $50(S_B - S_A)$.

On the other hand, B now also has an additional payout given by:

$$-50(F_A - S_A) + 50(F_B - S_B) = 50(F_B - F_A) + 50(S_A - S_B)$$

This includes a fixed amount $50(F_B - F_A)$ which is effectively the fee for providing the basis swap, and the basis swap itself, $50(S_A - S_B)$, in the opposite direction to A's basis swap.

In this trading period with these two additional CFDs, the revenues would be:

$$\text{Revenue } A(\text{with synthetic FTR}) = 150 \times 50 + 100 \times (50 - 100) + 50 \times (100 - 50) = \$5{,}000$$

$$\text{Revenue } B(\text{with synthetic FTR}) = 50 \times 100 + 100 \times (50 - 50) + 50 \times (50 - 100) = \$2{,}500$$

With the basis swap, gentailer A has achieved the desired hedging, but instead of the $2,500 payout being funded from rentals it is funded by gentailer B who's revenue has fallen by $2,500. The rentals are still the same, but this time they are not used to settle the basis swap.

[33] This example was set up to ensure that rentals fully funded the FTR payout. In reality this will only occur under certain conditions in this example because the two gentailers also face residual volume risk in their generation.
[34] This would leave our simple market with no rentals after paying out on the FTR.

This example highlights points of difference between FTRs and the basis swaps that can be created once the futures market is sufficiently liquid:

1. FTR payouts are funded by rentals left over in the spot market each month, whereas basis swaps are funded by hedge market participants.
2. FTRs can be purchased by one market participant without reference to any other market participant, whereas a basis swap requires the trading of two CFDs or futures contracts with at least one other hedge market participant. In the example above, A traded both CFDs with B, but in the real market A could have traded one contract with each of two other parties. If using futures, then the other party would be the futures exchange, requiring only that there were other futures players who wished to buy and sell at the prices offered and bid by A.
3. Buying and selling CFDs to create a basis swap creates a new risk for B, but then B is compensated for this risk by the small difference in the strike prices of the two CFDs. If A hedged with two parties, or if A had used futures contracts instead of CFDs, then we can assume that the other two parties involved would have made these transactions because they wished to hedge spot price risk.
4. Purchasing the FTR appears, on the face of it, not to create a corresponding risk or benefit for any other party because the rentals are used to fund FTR payouts, i.e. no additional payments are required from market participants. In reality, the rentals are distributed to those that pay transmission charges, representing a source of revenue to those parties. Without FTRs this revenue stream is highly volatile. With FTRs available for auction, FTRs are priced and paid for in advance, based on expected price differences across the grid: the auction revenues are therefore likely to be significantly less volatile than the rentals themselves. Thus the benefit to the parties that pay transmission charges is lower volatility, and hence lower risk, in their respective rental revenues.

6.2 Do FTRs Help Futures?

Basis swaps are funded by hedge market participants, whereas FTRs are effectively funded by the parties that receive rentals revenue. Therefore the proposed FTRs represent another source of hedge instruments which could increase the total volume of hedges available to the market. All other things being equal, the presence of FTRs in the market could possibly reduce the need to use futures to create basis swaps, for example, thus reducing liquidity in the futures market overall. On the other hand, the payout equivalence of FTRs and basis swaps could possibly create greater interest in both types of instrument.

The Australian electricity futures market is very liquid and trades far in excess of the total physical market. At the same time, the Australian market offers an instrument similar to FTRs known as a Settlement Residue Auction (SRA). The presence of SRAs in the market does not appear to have hindered the growth of liquidity in futures. Futures and FTRs, or their equivalent, also co-exist in LMP markets in North America.

In our opinion, the payout equivalence of FTRs and basis swaps, is likely to promote interest in both these types of instrument, which would suggest that the presence of FTRs in the market could actually promote liquidity in the futures market, and vice versa.

6.3 FTR Design

The EC's FTR proposal is silent on a number of design details, and also includes elements which may be subject to change after submissions are received during consultation. Two key issues are discussed briefly in this section.

6.3.1.1 GWAP versus Nodal Prices

In developing simple formulae which can be applied to FTRs in hedging strategy, we have shown that a location factor adjustment is required when using GWAP hub prices to hedge spot exposure in another island. The FTRs could also reference particular nodes, e.g. Benmore and Otahuhu, and in this case a similar adjustment would be required. In other words, the GWAP hub prices can for all intents and purposes be treated as nodal spot prices.

However, GWAP hub prices are not currently directly observable in the market, although once defined they could be back-calculated and published by the EC, and published for every trading period in future. The use of GWAP prices introduces additional complexity for what seems to be little gain (in terms of integrating FTRs into hedging strategy). On the other hand, using GWAP prices could reduce the impact of market power, and GWAP prices appear to be a little less volatile than nodal prices.

However, there are obvious advantages in referencing both FTRs and futures to the same prices, either nodal or GWAP. This would reduce complexity and provide a more natural linkage between FTRs and the futures market, which could potentially assist the growth of liquidity in the hedge market overall.

6.3.1.2 Form of the FTR

The form of FTR assumed in this report 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.

The EC's proposal does not specify which payout formula is to be used, and effectively leaves the choice to the detailed design phase of FTR development. If the loss-adjusted form is used, then the loss factor must be included in the location factor adjustments given in this report. For example, the formula for the independent retailer (section 5.1) 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 H_A appears in the formulae, $L_{AB}H_A$ would appear.

Including loss factors in FTRs makes them more complex to apply to hedging strategies, which would indicate that the simpler form of FTR is preferred. But if loss factors are included then market participants will need to establish the likely range of these additional variables in either direction in order to optimise their hedging strategies, requiring modelling of expected power flows and losses.

6.3.1.3 FTR Quantity

Earlier proposals for FTRs featured a quantity Q in MW, rather than the MWh per half hour assumed in this report. The choice of MW or MWh will be made during the detailed design phase. If FTRs are actually specified in MW, then to apply our formulae, the conversion between MW and MWh per half hour must be made by dividing the MW quantity by two.

6.4 FTRs and Smaller Players

The proposed FTRs are initially likely to appeal to larger, portfolio players and larger projects, rather than to smaller players. New-entrant retailers and generators, in particular, may initially face a number of barriers to using FTRs, including:

- developing the internal knowledge, skills and tools needed to work with hedges and FTRs;
- prudential requirements for obligation FTRs;
- timing of cash flows: FTRs have to be purchased and paid for well in advance of the corresponding spot settlement month;
- building up sufficient load in an island to warrant purchasing FTRs;
- lack of flexibility (compared to, for example, a structured hedge deal with a party in a particular region).

When FTRs are initially available, we expect that smaller players will continue to look for simpler, more flexible ways to hedge price risk within regions, and the regions they target will be those in which these hedges can be found. But over time, as the market in general gains experience with FTRs, smaller players may be expected to expand their capabilities and will look to alternatives including FTRs.

However, we believe the key for smaller players is actually the development of liquidity in the overall hedge market, which is likely to be assisted by the presence of FTRs, as a compliment to futures. As financial intermediaries enter the market, assuming they will trade FTRs in addition to futures, the benefits of FTRs to smaller players are more likely to be obtained indirectly through access to a wider range of hedging instruments via larger market participants and the intermediaries.

For example, a smaller player wishing to hedge LPR between the islands may trade a basis swap with an intermediary who in turn hedges this risk either with an FTR purchase or using basis swaps in the futures market.

7 Appendix A – Hedge Theory

This Appendix introduces hedging theory and develops the theory behind location factor adjustments in general.

An FTR is generally conceived as a single hedging instrument with value proportional to the difference between two nodal prices (refer also to Figure 6):

7-1: $\quad Cash\ flow = Q(S_B - S_A)$

where Q is a fixed notional quantity in MWh per half hour and S_A and S_B are the prices at two nodes distant from each other on the grid, as shown below. The two nodal prices vary by half hour, and the notional quantity Q, which is set in advance at the time the FTR is agreed between two parties, may also vary by half hour, but for the sake of simplicity we drop (where the context allows) any reference to time in our equations.

Under the EC's proposal, and as occurs in other jurisdictions, FTRs would be auctioned and sold to the highest bidders. A second exchange of cash occurs, therefore, which is just the amount bid for the FTR in the first place, which we will call FTRCost. The total cash flow associated with the FTR is therefore given by

7-2: $\quad Cash\ flow = Q(S_B - S_A) - FTRCost$

An FTR is a purely financial instrument, established under contract between the FTR provider and the FTR purchaser. The notional quantity, Q, may be expressed in MWh but this is a convenience which simplifies the integration of the FTR into a hedging strategy: it is important to keep in mind that only cash exchanges hands, and that no physical supply or purchase of electricity is provided for, or even implied by, the existence of the FTR.

The hedge market has transacted for many years in "swaps" which are also purely financial instruments, and commonly referred to as "contracts for difference" or CFDs (or just 'hedges'). The cash flow associated with a CFD in a half hour is the difference between a fixed strike (or hedge) price and the spot price at a specified node, multiplied by a notional quantity Q:

7-3: $\quad Cash\ flow = Q(F - S_A)$

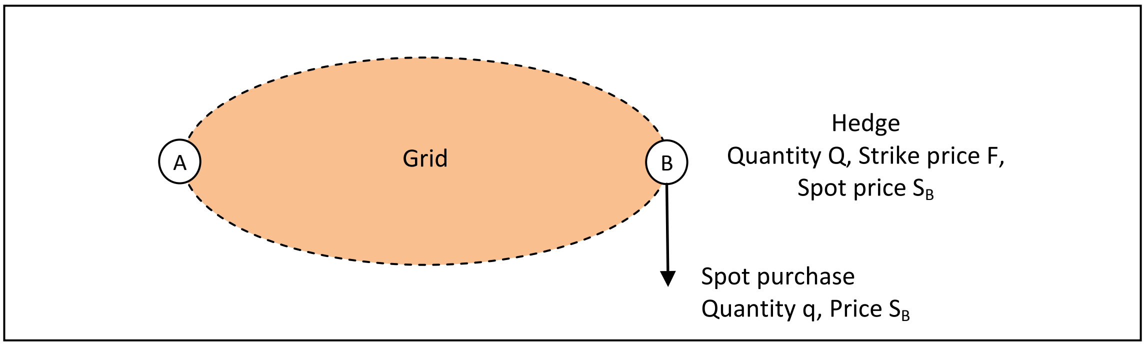
The seller of the CFD receives cash when the spot price is lower than the strike price, and the buyer of the CFD receives cash when the spot price is higher than the strike price. Swaps are signed up at one time, and settled (by payment of cash from party to the other) once the spot prices are known, typically after the end of the month they relate to. These cash flows occur more or less at the same time as market participants settle their spot market transactions.

Futures contracts have the same basic form as CFDs, but the cash flows associated with a futures contract commence the first business day after the futures contract is bought or sold – refer to section 3.2 for a full description of the cash flows associated with futures contracts.

7.1 A Basic Hedging Strategy

Suppose now that a spot market purchaser wishes to hedge their spot market purchases at a single node, as fully as possible – what one would refer to as a "100% hedge".

Figure 9: Spot Market Purchaser with Hedge at Off-take Node



They may be either a retailer supplying load at a node, or a large consumer purchasing directly from the spot market or at spot prices via a retailer. They could do this simply by purchasing a CFD at their node, and their total cost in a half hour would be given by:

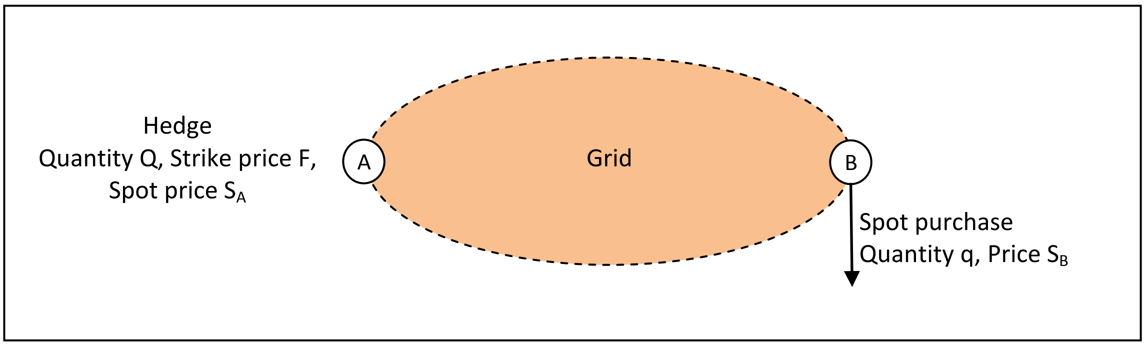
7-4: $$Cost = qS_B + Q(F - S_B)$$

where Q is the hedge quantity, F the strike price, S_B the price at their off-take node, and q the quantity actually purchased from the spot market in the half hour. If q and Q are the same in a half hour then a little algebra quickly shows that their cost is just QF. This is the fixed hedge quantity multiplied by the fixed strike price, and so is a fixed cost. In other words, if our purchaser could predict in advance their load q, then they could hedge away their price risk using a CFD at their purchase node B, just by buying a CFD with Q = q.

In reality, load cannot be predicted in advance. However, it can usually be predicted accurately enough so that a CFD can be purchased which achieves close to a 100% hedge on average.

LPR arises when a CFD cannot be purchased at the spot market purchasing node.

Figure 10: Spot Market Purchaser with Hedge at Off-take Node



Suppose that a CFD is purchased at node A which has spot price S_A, so then the hedging strategy would give:

7-5: $$Cost = qS_B + Q(F - S_A)$$

If S_B and S_A vary in strict proportion to each other, then we can define a new quantity called the relative location factor (or just location factor) between the two nodes as:

$$\ell = \frac{S_B}{S_A}$$

and achieve a 100% hedge by setting Q = ℓq which is to say that we scale the hedge quantity up by the relative location factor[35]. If we do this, then we will also find that our cost will be ℓQF and our average price ℓF. Section 7.2 includes the details of how the location factor adjustment is derived.

Making this location factor adjustment works well if the location factor is stable and predictable, but otherwise a substantial residual LPR can remain. Enter the FTR, which can augment the cost in an intuitive way:

7-6: $$Cost = qS_1 + Q(F - S_A) - Q(S_B - S_A)$$

which simplifies to $Cost = qS_B + QF - QS_B$ or

7-7: $$Cost = (q - Q)S_B + QF$$

Under the assumption that we can predict our load well in advance and achieve q ≈ Q then the cost is approximately QF, which is fixed. In this case, because we are no using an FTR, there is no need to make an adjustment to the hedge quantity to account for the location factor between the two nodes.

We have, however, missed an important cost in the above: recall that an FTR must be purchased via an auction. Then the total cost is actually given by

7-8: $$Cost = (q - Q)S_B + QF + FTRCost$$

which means that the purchaser doesn't get something for nothing.

7.2 Location Factor Adjustments

A location factor adjustment to a hedge quantity is not strictly an LPR hedge, but it does ensure that (in the absence of any other LPR hedge) the location factor between the physical off-take, or injection node, and the hedge node is optimised to achieve any particular target level of hedge cover on average.

For a single physical node to be hedged at a distant node, there is a significant degree of 'location basis risk' which should be factored into a hedging strategy. A hedging analysis is based on input data which represents spot prices at each of the two nodes, perhaps historical data or some form of price forecast. On the assumption that the input data actually occurs (the deterministic case) a perfect "Deterministic hedge" is formed with a hedging ratio equal to the location factor of the physical node relative to the

[35] The location factor should be calculated in a particular way, which is given in section 7.2.

hedge node. This ratio ensures that the net price is fixed over the hedging period given a single hedge with hedge quantity and strike price as fixed parameters: Q(F – S).

The hedging ratio is the ratio of the hedge quantity, Q, to the expected average demand or injection over the hedging period.

A hedging ratio can also be formed in the non-deterministic case using simple statistics concerning the behaviour of prices at the physical node and the hedge node. In this case the hedge ratio which minimises volatility in the total cash flows over the period is given by the covariance of the two prices divided by the variance of the price at the hedge node. We call a hedge with this ratio a "Minvar hedge".

The hedge ratios for Deterministic and Minvar hedges can be significantly different in cases where there is extreme volatility in the relative location factor of the two nodes, including price inversions, e.g. as occurs between the two islands. Care must be taken in this case in selecting the input data for the hedging analysis and the hedger should carefully evaluate the merits of using either strategy over a wide range of scenarios.

These results can be easily extended to a hedging strategy involving demand or injection at multiple nodes hedged at one reference node. The following sections develop hedging ratios on the assumption that the hedger is a hedge buyer, for example a retailer or a large consumer exposed to spot price.

7.2.1 Case 1: Single Physical Node

To simplify the text below we'll use the term quantity, q, to refer to demand or generation taken or injected, respectively, at the node where physical supply takes place. In a simple case of one physical node B and one hedge node A, the revenue or cost over a series of trading periods 1, ..., T is given by

$$\sum_{t=1}^{T} q^t S_B^t + \sum_{t=1}^{T} Q(F - S_A^t)$$

where S denotes spot price, F is the fixed strike price and Q the fixed hedge quantity. This can be rewritten as

$$TQF + \sum_{t=1}^{T} q^t S_B^t - Q\sum_{t=1}^{T} S_A^t$$

This analysis is usually done looking forward using a set of forecast spot prices, which means there is uncertainty in their value. But if we have faith in our forecast spot prices, then we might decide to select Q to give a Deterministic hedge, in which we want the cost or revenue to simply equal TQF, a fixed price. The condition for a Deterministic hedge is therefore that the last two terms in the above equation net to zero:

$$\sum_{t=1}^{T} q^t S_B^t = Q\sum_{t=1}^{T} S_A^t$$

which leads to our first key result

7-9: $$Q = \frac{\sum_{t=1}^{T} q^t S_B^t}{\sum_{t=1}^{T} S_A^t}$$

To help us understand this result we will distinguish between the quantity-weighted average price and the time-weighted average price, $\hat{S}$ and $\bar{S}$, respectively:

$$\hat{S} = \frac{\sum_{t=1}^{T} q^t S^t}{\sum_{t=1}^{T} q^t} \quad \text{and} \quad \bar{S} = \frac{\sum_{t=1}^{T} S^t}{T}$$

Substituting these into (7-9) gives us $Q = \frac{\hat{S}_B \sum_{t=1}^{T} q^t}{\bar{S}_A T}$

which can be written as

7-10: $$\frac{Q}{\bar{q}} = \frac{\hat{S}_B}{\bar{S}_A}$$

The ratio $\frac{Q}{\bar{q}}$ is known as the 'hedge ratio' or 'hedging ratio.'

Equation (7-10) gives the constant hedge ratio (and hence hedge quantity, Q), which produces a fixed total cost or revenue over the period concerned, assuming that spot prices turn out to be equal to our forecast and that we know q in advance. In words, the optimum hedge ratio is the quantity-weighted average spot price at the physical node, divided by the time-weighted average price at the hedge node.

We refer to the resulting location factor $\frac{\hat{S}_B}{\bar{S}_A}$ as the "aggregate location factor" thus avoiding calling it the average location factor (which can be significantly different to the aggregate location factor).

In many applications the quantity is either almost constant, or the impact of the quantity profile is small[36], and the aggregate location factor can be simplified by using the time-weighted average location factors $\frac{\bar{S}_B}{\bar{S}_A}$.

[36] Large generators who can change their injection quantities may not be able to make this approximation.

7.2.2 Case 2: Multiple Physical Nodes

The key results above can be extended to a common situation where the hedger has a number of physical nodes, which we assume are either all demand or all injection nodes, and seeks to find a Deterministic hedge at one hedge node A.

The notation is a little more complex with more nodes - assume there are now physical nodes 1 up to N, indexed by n in the following equations and write the quantity at node n in period t as q_n^t and spot price at node n as S_n^t. The total cost or revenue over T trading periods is now expressed as

$$\sum_{t=1}^{T} q_1^t S_1^t + \ldots + \sum_{t=1}^{T} q_N^t S_N^t + \sum_{t=1}^{T} Q(F - S_A^t)$$

or

7-11: $$TQF + \sum_{t=1}^{T} q_1^t S_t^1 + \ldots + \sum_{t=1}^{T} q_N^t S_t^N - Q\sum_{t=1}^{T} S_A^t$$

The condition for a Deterministic hedge is once again that the cost or revenue is fixed with a value of TQF, which gives us

$$Q = \frac{\sum_{t=1}^{T} q_1^t S_1^t + \ldots + \sum_{t=1}^{T} q_N^t S_N^t}{\sum_{t=1}^{T} S_A^t} = \frac{\sum_{t=1}^{T} q_1^t S_1^t + \ldots + \sum_{t=1}^{T} q_N^t S_N^t}{\bar{S}_A}$$

which can be written as

7-12: $$Q = \frac{\bar{q}_1 \hat{S}_1 + \ldots + \bar{q}_N \hat{S}_N}{\bar{S}_A}$$

Equation (7-12) says that the hedge quantity should be the sum over the N nodes of the product of the time-weighted average nodal quantity and quantity weighted average nodal price, divided by the time-weighted average price at the hedge node A.

We could also express the hedge quantity as a proportion of the total average quantity over all N nodes $\bar{q} = \frac{\sum_{t=1}^{T}\sum_{n=1}^{N} q_n^t}{T}$ which would give us

7-13: $$\frac{Q}{\bar{q}} = \frac{\bar{q}_1}{\bar{q}} \frac{\hat{S}_1}{\bar{S}_A} + \ldots + \frac{\bar{q}_N}{\bar{q}} \frac{\hat{S}_N}{\bar{S}_A}$$

Equation (7-13) says that the optimum hedge ration is equal to the quantity-weighted average of the aggregate location factors at each of the N nodes relative to the hedge node A.

As in Case 1, in many applications the time-weighted average prices can be used in calculating the aggregate location factors at each node.

Another approach to the multi-node hedging problem is simply to add the hedge quantities calculated at node A for each of the N off-take or injection nodes, and add these up to give the total hedge quantity at node A.

7.2.3 Case 3: Single Physical Node, Volatile Prices

In the cases above we implicitly assumed that spot prices are known in advance, which is called a deterministic analysis[37]. In practice, they don't of course, so in this case we look at another way to formulate a hedging strategy using the statistical properties of the spot price S_B at the physical node B, and at the hedge node, S_A. For convenience further on in the analysis, we'll call the cost or revenue function Ω so that

$$\Omega = qS_B + Q(F - S_A)$$

We will drop the time index, t, to make the equations clearer, but we should keep in mind that we are dealing with a hedge strategy covering multiple trading periods.

A perfect Deterministic hedge is actually impossible given that we can't forecast spot prices with certainty, so now we'll look for a hedging strategy that minimises volatility in Ω. Our measure of volatility is the standard deviation of Ω but we'll actually work with the variance of Ω, denoted var(Ω), the variance being the square of the standard deviation – this an easier quantity to work with than the standard deviation. We can write

$$\mathrm{var}(\Omega) = \mathrm{var}(qS_B + QF - QS_A)$$

We can simplify this immediately by noting that QF is a constant so its variance is zero, leaving

7-14: $$\mathrm{var}(\Omega) = \mathrm{var}(qS_B - QS_A)$$

A general result from statistical theory for two random variables X and Y is that

7-15: $$\mathrm{var}(aX + bY) = a^2\,\mathrm{var}(X) + b^2\,\mathrm{var}(Y) + 2ab\,\mathrm{cov}(X,Y)$$

where a and b are constants and cov(X,Y) is the covariance of X and Y defined as

$$\mathrm{cov}(X,Y) = E[(X-\mu)(Y-\nu)]$$

E[variable] denotes the expected value[38] of the variable and μ and ν are the expected values of X and Y, respectively, i.e. μ = E[X] and ν = E[Y].

[37] Since we assumed the spot prices are 'determined' (known) in advance.
[38] To be clearer, it is the value expected on average.

The covariance is a measure of how two random variables vary together, whereas variance is a measure of how much a single random variable varies on its own. If X and Y are independent variables then cov(X,Y) equals zero[39]. If X and Y tend to move together – which means that when X is above μ then Y tends to be above ν - then the covariance will be positive, but if they tend to move in opposite directions then the covariance will be negative.

Applying (7-15) to (7-14) gives us the variance of Ω, assuming that q is a constant for simplicity, which gives

$$\mathrm{var}(\Omega) = q^2\,\mathrm{var}(S_B) + Q^2\,\mathrm{var}(S_A) - 2qQ\,\mathrm{cov}(S_B, S_A)$$

Our aim is to minimise the variance of Ω by selecting the best value of Q, so we apply some calculus and take the partial derivative of Ω with respect to Q

7-16: $$\frac{\partial\,\mathrm{var}(\Omega)}{\partial Q} = 2Q\ \ \mathrm{var}(S_A) - 2q\,\mathrm{cov}(S_B, S_A)$$

To find the value of Q that minimises var(Ω) we set (7-16) to zero to give

$$0 = 2Q\ \ \mathrm{var}(S_A) - 2q\,\mathrm{cov}(S_B, S_A)$$

which can be rearranged to give us our final result:

7-17: $$\frac{Q}{q} = \frac{\mathrm{cov}(S_B, S_A)}{\mathrm{var}(S_A)}$$

Equation (7-17) tells us that to minimise the variance of Ω (i.e. to minimise its volatility and get as close as we can to a Deterministic 100% hedge given volatile spot prices), we should set the hedge quantity to the physical quantity multiplied by the covariance of the spot prices at the two nodes concerned, divided by the variance of the spot price at the hedge node A. Remember, however, that we have assumed at this point that the physical quantity q is constant.

7.2.4 Case 4: Multiple Physical Nodes, Volatile Prices

Finally, we'll extend our statistical analysis to the general case where we have a number of physical nodes with volatile prices and known quantities (or at least highly predictable quantities). In this case we wish to minimise the volatility of equation (7-11), and since TQF is constant this comes down to (dropping the time indices for simplicity)

7-18: $$\mathrm{var}(\Omega) = \mathrm{var}(q_1 S_1\ + \ldots + q_N^1 S_N - QS_A)$$

For simplicity we'll assume the q_n are all constants. Now we can apply two results from statistical theory for random variables X_1, ..., $X_{N:}$

[39] But if the covariance is zero this does not necessarily mean the random variables are independent.

$$\mathrm{var}(\sum_{i=1}^{N} X_n) = \sum_{i=1}^{N}\sum_{j=1}^{N}\mathrm{cov}(X_i, X_j)$$

and

$$\mathrm{cov}(aX_i, bX_j) = ab\,\mathrm{cov}(X_i, X_j)$$

to rewrite (7-18):

$$\mathrm{var}(\Omega) = Q^2\,\mathrm{var}(S_A) - 2\sum_{i=1}^{N} q_i\,\mathrm{cov}(S_i, S_A) + \sum_{i=1}^{N}\sum_{j=1}^{N} q_i\,q_j\,\mathrm{cov}(S_i, S_j)$$

As in Case 3 above, we differentiate with respect to find the value of Q which minimises the volatility of Ω and finally get

7-19: $$Q = \frac{\sum_{i=1}^{N} q_i\,\mathrm{cov}(S_i, S_A)}{\mathrm{var}(S_A)}$$

which looks very similar to the result for one physical node, equation (7-17).

Equation (7-19) tells us that to minimise the variance of Ω over multiple physical nodes, i.e. to minimise its volatility and get as close as we can to a 100% hedge given volatile spot prices, we should set the hedge quantity, Q, to the quantity-weighted sum of the nodal price covariances, and divide this sum by the variance of the spot price at the hedge node A. Again note that we have assumed the physical quantities at N nodes, q_1, ..., q_N are constant.

7.2.5 Application Notes

We now have some equations to work with but they look rather complex for multiple nodes. We also have two different forms of equation depending on whether we take a deterministic approach as in Cases 1 and 2 or a statistical approach as in Cases 3 and 4.

For many applications the correlation between physical quantity and price can be quite low, e.g. in the case of a consumer with a flat load profile, or maybe a generator offers everything at a low price and tends to run base-load. We should also note that the volatility in spot price tends to be much greater than the volatility in quantity. These factors often combine to make our assumption of constant physical quantity q over the hedging period very workable.

Furthermore, hedging periods are often tailored to demand or generation, so a consumer or generator with a flat load will be happy with base-load hedges. But if they have a demand or injection profile that has a different profile, they might seek hedge quantities that match that profile. In this case the constant physical quantity adjusts in line with the hedging period being analysed.

Let us now look at two examples with one physical node and one hedge reference node, first for BEN and STK, the second for BEN and HLY.

7.2.6 Case Studies

In our first example we look at buying or selling at BEN and hedging at STK[40], and vice versa, using monthly average prices from Oct-96 to Feb-07. The following tables summarise the results for two ways of hedging: the first is the Deterministic hedge derived in Case 1 using the ratio of the average prices over the period, and the second is the Minvar hedge' which uses the result from Case 3. The hedge prices used in the analysis are the average prices over the sample period. All hedges are worked out using 1 MWh per period and the months are treated as just one period each, giving us smaller numbers to work with. The simple average location factor is included in the tables for interest only.

Table 2: Optimum Hedge Quantities for BEN and STK

Hedge Proportions	Hedge STK at BEN	Hedge BEN at STK	Hedging Application
Ave LF	1.093	0.915	Interest Only
Ave Price/Ave Price	1.102	0.907	Perfect Hedge
Covar(Physical)/Var(Hedge)	1.123	0.875	Minvar Hedge

The first case is hedging physical quantity at STK with BEN as the hedge node. The average location factor STK/BEN is 1.093 but the Deterministic hedge is formed with the ratio of the average nodal prices which gives 1.102. Using covariance and variance gives a hedging ration of 1.123.

In our second case study we look at BEN and HLY[41] which are in different islands.

Table 3: Optimum Hedge Quantities for BEN and HLY

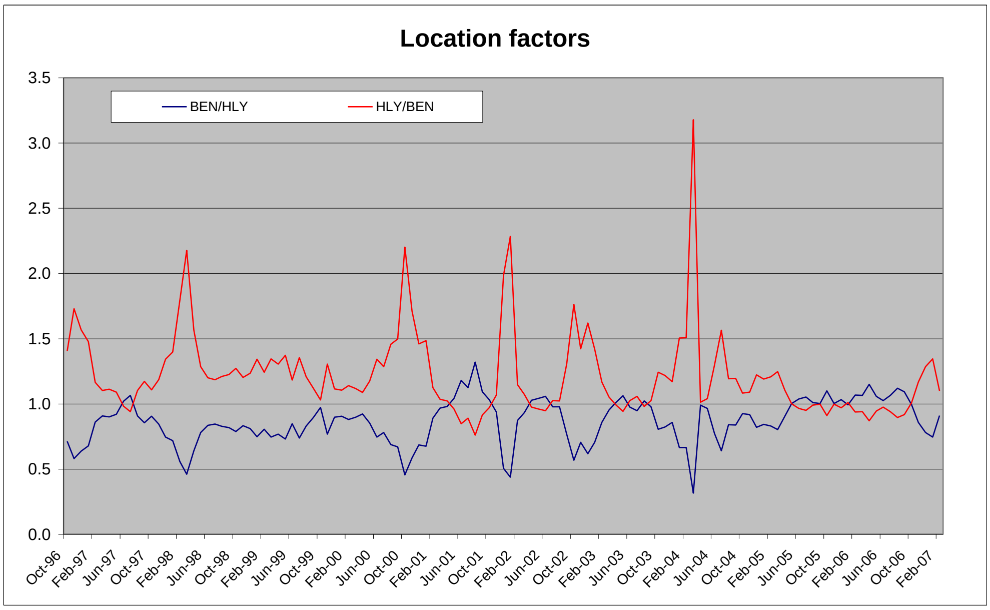
Hedge Proportions	Hedge BEN at HLY	Hedge HLY at BEN	Hedging Application
Ave LF	0.862	1.218	Interest Only
Ave Price/Ave Price	0.910	1.099	Perfect Hedge
Covar(Physical)/Var(Hedge)	1.132	0.829	Minvar Hedge

In this case the hedging ratios for the Deterministic and Minvar hedges are quite different. The following chart shows monthly location factors. There are months in the sample period in which the usual direction of power flows on the grid between BEN HLY is reversed, giving reversed location factors. During these months the Deterministic Hedge takes large excursions from typical values, whereas the Minvar hedging ratios are set in anticipation of these excursions.

A good indication that hedging at a distant node, with an adjustment in hedge ratio based on expected aggregate location factor, will not provide a good hedge, is that the Deterministic and Minvar hedge ratios are significantly different – as they are in this case. The BEN-HLY example also illustrates how different average location factors can be from the aggregate location factors required for adjusting hedge quantities.

[40] The STK2201 node is at Stoke near the top of the South Island.
[41] The HLY2201 node is at Huntly south of Auckland.

Figure 11: Location Factors BEN/HLY and HLY/BEN



7.2.7 Theory Conclusion

The Deterministic Hedge and Minvar Hedges will produce similar hedging ratios for node pairs which have relatively predictable relative location factors. But when constraints, or flow reversals, push location factors to extreme levels the Minvar hedge approach should definitely be considered.

However, a note of caution must be added on its use: any analysis of location basis risk relies on assumptions around the data being used, and hedgers need to be aware that this data may be different to what actually happens in the market. In particular, a Minvar hedge with hedging ratio very different to the hedging ratio for the Deterministic Hedge will produce quite different cash flows than the Deterministic Hedge in some cases.

7.3 Pricing Hedges and FTRs

It can be shown[42] that the price of an electricity futures contract is given by

7-20: $F = E[S^T]$

which is to say that the futures price should be the expected value of the relevant spot price at the time, T, to which the futures contract relates.

For all intents and purposes the price of a CFD is also the expected spot price, although some authors have produced a slight variation on (7-20) which takes account of the fact that the cash settlement of a CFD takes place just after maturity[43]. However, this is generally a small adjustment to price and is typically ignored.

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[42] See, for example, John C Hull, *Options, Futures and Other Derivative Securities*, Prentice Hall, 1989 or subsequent editions.

[43] For example, see H Geman and O Vasicek, *Plugging into Electricity*, Risk Magazine, July 2001. The authors derive the expression $F = \frac{1}{B(t,T)} E[S^T] \frac{M(t)}{M(T)}$ where B(t,T) is the price at time t of a bond of unit face value maturing at time T, and M() is the "money market account" which is to say the interest rate on short

The result in (7-20) is derived assuming a world which is "risk neutral", or at least behaves in aggregate which appears risk neutral. Risk neutrality implies that market participants are indifferent between two market outcomes with different risks attached, as long as they have the same expected pay-off. Of course, electricity hedge buyers and sellers are anything but risk neutral: they are far more likely to be risk averse, which is to say that they prefer a lower risk outcome with the same pay-off as other outcomes. After all, that is why they hedge in the first place.

However, assuming that both hedge buyers and sellers are risk averse, then they are still likely to agree on hedge prices which appear to be risk neutral. If they did not, then one side of the market would pay a premium for hedges while the other would hedge at a discount. While risk premiums may creep into hedge prices from time to time, the evidence is that over the long term (7-20) actually does hold in the New Zealand electricity market.

Pricing an FTR, which pays out depending on the difference between two futures spot prices $S_1 - S_0$ is a simple extension of (7-20):

7-21: $FTR\ price = E[S_1^T] - E[S_0^T]$

7.4 Valuing Hedges and FTRs

The hedges that are of interest in this application report are all purely financial contracts between either two parties, or with a futures exchange, and they also involve the transfer of cash at some time in the future. The theoretical value of a hedge is therefore the discounted, expected cash flow of the hedge over its lifetime. In many cases the cash flow occurs only at maturity: for example, the cash flow associated with a CFD at Haywards for the month of October 2015 will only have an exchange of cash in the days following 31 October 2015, at which point all spot prices at Haywards for that month will be known and the half hourly cash settlements can be calculated.

We can write

7-22**:** $Value = e^{-rT} E[F^T - S^T]Q$

where r is the appropriate discount rate, T gives the future time (from today) that the hedge is settled, Q is the hedge quantity and $E[F^T - S^T]$ is the expected value of the difference payment (which also equates to the strike price F minus the expected spot price $E[S^T]$).

If instead the hedge is a futures contract at Haywards for October 2015, then cash flows will occur earlier due to the daily settlement of futures contracts against the prevailing futures price (and against the average Haywards price for October 2015 on 31 October 2015). Since the price of the futures contract is the expected spot price, the process of

term cash deposits in the money market. If bonds are priced at par and the term structure of interest rates is flat, then this equation reduces to (7-20). Even if it doesn't reduce exactly, it will almost always be close to (7-20).

daily settlement ensures a rather counter-intuitive result: the value of the contract is maintained at zero throughout its entire life[44].

For an FTR the value is given by:

7-23: $$Value = e^{-rT} E[S_1^T - S_0^T]Q$$

The above results are all based on the theoretical derivation of the value of a financial instrument. However, if the instrument trades in a liquid and transparent market then the value of the instrument can be observed directly as the price of the same instrument as it is traded, rendering discounted cash flow valuation unnecessary. For example, if a CFD covering October 2013 is purchased in March 2012 and valued in August 2012, and if there is a transparent and liquid market for CFDs in August 2012, then the value of the original CFD is established by the August 2012 price of the same CFD. Suppose the strike price of the CFD purchased in March 2012 is $80/MWh and the August 2012 traded strike price is $100/MWh then the value of the CFD is $20/MWh multiplied by the hedge quantity. The rationale for this is that a hedge buyer prepared to buy a $100/MWh CFD in October 2013 CFD would also be prepared to pay $20/MWh for the $80/MWh CFD.

7.5 Adjustments Required for GWAP Hub FTRs

The EC's proposed FTRs do not reference any particular nodes. Instead, they reference prices in each island which the generation-weighted average prices in the respective island. This section develops the theory behind the adjustments required to optimise hedging strategy given that the FTR's GWAP prices are not actual nodal prices.

7.5.1 Case 5: FTR for a Single Physical Node

As in Case 1, we start with a physical spot exposure, which can be either a spot purchase of injection, and add and FTR, but starting with a single trading period. The physical exposure is at node B which is in the island with GWAP hub price H_B, and the CFD or futures is at node A which is in the island with GWAP hub price H_A. The
The purchaser would purchase an FTR one way, and the generator would purchase an FTR in the other direction:

$$Purchase\ Cost = qS_B + Q(F - S_A) - Q_{FTR}(H_B - H_A)$$

$$Generation\ Revenue = qS_B + Q(F - S_A) + Q_{FTR}(H_A - H_B)$$

These two equations are identical (which is easy to show with some simple algebra), and rearrange to

[44] This begs the question: why anyone would enter into a futures contract if it has zero value? In fact, the question also applies to a CFD on the day it is purchased because on that day it also has an expected value of zero. The answer is that the hedge reduces risk, which has value over and above any considerations of the cash flow on the hedge. For example, a good hedging policy will produce more stable earnings for a listed electricity gentailer, which may lead to a higher share price. A small retailer can also avoid the costs of financial distress if it maintains a comprehensive hedge portfolio covering its spot purchases.

$$QF + qS_B - QS_A - Q_{FTR}H_B + Q_{FTR}H_A$$

Of the five terms in the above equation, only QF is fixed, so for a 100% hedge we require

7-24: $$qS_B - QS_A - Q_{FTR}H_B + Q_{FTR}H_A = 0$$

But (7-24) contains the hedge quantity, Q, and the FTR quantity Q_{FTR}, both of which need to be chosen when the hedge and FTR are transacted. For simplicity, and because this makes sense given that we are working with an FTR, we choose Q = Q_{FTR} and then (7-24) solves to give for the optimum hedge ratio

7-25: $$\frac{Q}{q} = \frac{S_B}{H_B + S_A - H_A}$$

In effect, (7-25) gives a composite location factor adjustment which takes account of the location factors between nodes A and B, and also between the island GWAP hubs and nodes A and B.

This result can expanded, using the approach used for Case 1 in section 7.2.1, to accommodate multiple trading periods to give

7-26: $$\frac{Q}{\bar{q}} = \frac{\hat{S}_B}{\bar{H}_B + \bar{S}_A - \bar{H}_A}$$

In other words, the optimum hedging ratio (which is expressed relative to the average quantity over the period) is the quantity weighted average price at the physical node B, divided by the numerator which features the time-weighted averages spot price at node A and the two time-weighted average hub prices.

As for Case 1, in many applications $\bar{S}_B$ can be used instead of $\hat{S}_B$ which simplifies hedging strategy.

7.5.2 Case 6: FTR for a Multiple Physical Nodes

We can extend the multi-period analysis to multiple nodes as did in Case 2, and get

7-27: $$\frac{Q}{\bar{q}} = \frac{\bar{q}_1}{\bar{q}}\left(\frac{\hat{S}_1}{\bar{H}_B + \bar{S}_A - \bar{H}_A}\right) + \ldots + \frac{\bar{q}_N}{\bar{q}}\left(\frac{\hat{S}_N}{\bar{H}_B + \bar{S}_A - \bar{H}_A}\right)$$

or we can simply add up the hedge values for each of the N nodes to give the total hedge and FTR quantity required at node A and in the FTR, respectively.

7.5.3 Case 7: FTR for a Single Physical Node with Volatile Prices

Following the method of Case 3, we can derive a result for a spot exposure at a single physical node B in one island, hedged at node A in the other island and assuming that load, q, is constant. The optimum hedge ratio in this case is given by

$$\frac{Q}{q}=\frac{\operatorname{cov}(S_B,S_A)-\operatorname{cov}(S_B,H_A)+\operatorname{cov}(S_B,H_B)}{\operatorname{var}(S_A)+\operatorname{var}(H_A)+\operatorname{var}(H_B)-2\operatorname{cov}(H_A,H_B)-2\operatorname{cov}(S_A,H_A)+2\operatorname{cov}(S_A,H_B)}$$

While this result is of interest in terms of completing the picture, given the uncertainties inherent in estimating future spot prices and their statistics, and the uncertainties in forecasting physical off-take or injection, it is debatable whether there is much to be gained in its application, over and above the use of the result in equation 7-26.

For similar reasons, we do not go on to derive the corresponding result for multiple nodes with volatile prices.

8 Appendix B – Comparison of LPR Hedging Methods

Table cells left blank do not apply to the method. In the following table "information asymmetry" refers to a situation in which some participants in the wider hedge market have better information than others. For example, generators may have better information about the timing and impact of plant outages than large consumers and smaller retailers. Information asymmetry is known to have the potential to inhibit trading in some markets.

Table 4: Comparison of LPR Hedging Methods

Method	FTRs Proposed by EC	Basis Swaps	OTC Hedge Market	Rentals allocation proposed by EC	Regional Integration	Location Factor Adjustments
Contract specifications	1 month duration 0.25 MW base-load 0.25 MW peak time zone	1 quarter duration 1 MW base-load at OTA, WKM, BEN	Flexible: customised between the parties			
Availability	Up to 24 months in advance, quantity available dependent on the requirement for revenue adequacy	Up to 3 whole years plus current part year in advance	Dependent on OTC market at the time of sale of purchase	By default	Can be difficult for smaller players to find regional partners Takes time to establish regional customer bases	
Procurement process	By auction Prudential requirements must be met for obligation FTRs	ASX Futures market	OTC party to party		Customers can be purchased from other retailers Can build generation	
Cash flow implications	Purchase price paid at time of auction, settled in the month after maturity month	Daily settlement and the possibility of margin calls	Settlement in the month after the maturity month	Rentals received in month after maturity month	Spot settlements in month after maturity month	
Liquidity	Up to physical quantity available at auction	At least up to the target mandated by reforms	Low - moderate			
Tradability	Tradeable with approved FTR holders	High	Nil – low		Customers and generation can be bought and sold	
Transparency	Moderate - High	High	Low – moderate	Moderate – high	Low – moderate	
Information asymmetry	Moderate	Moderate	Moderate			
Market power	Possible at auction and during maturity month	Possible	Possible	Indirectly possible	Possible	
LPR hedge effectiveness	High	High	High	Low	High	Low – depends on volatility of location factors
Residual price risks	Location factor between hub	Location factor between	Location factor between	High	Location factors within	Relevant location factor

Method	FTRs Proposed by EC	Basis Swaps	OTC Hedge Market	Rentals allocation proposed by EC	Regional Integration	Location Factor Adjustments
assuming 100% hedge	and spot nodes	futures and spot nodes	hedge and spot nodes		regions	
IFRS requirements	Yes	Yes	Yes			
Force majeure or scaling	Possible	No	Possible	Possible due to FTR settlements process		
Restrictions on trading	Yes – prudential requirements and Securities Commission	Securities Commission authorisation	Securities Commission authorisation			
Tools and resources	Forecasts, analysis	Forecasts, analysis	Forecasts, analysis		Generation and retail businesses	Forecasts, analysis
Complexity	Moderate - High	Moderate	Moderate	Low	Moderate - high	Moderate - high