



NEW ZEALAND INSTITUTE FOR THE STUDY
OF COMPETITION AND REGULATION INC.

**Economic Analysis of Financial Transmission Rights (FTRs)
With Specific Reference to the Transpower Proposal for
New Zealand**

LEWIS EVANS*
EXECUTIVE DIRECTOR

AND

RICHARD MEADE**
RESEARCH PRINCIPAL

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* Lewis Evans is a member of the Market Surveillance Committee (MSC) of the New Zealand Electricity Market. Nothing in this report is intended to represent, or should be interpreted as representing, the views of either the MSC or of Lewis Evans acting in his capacity as a member of the MSC.

** Director, Cognitus Advisory Services Limited.

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1. Introduction and Summary

This economic analysis of FTRs has been prepared with specific reference to those proposed by Transpower New Zealand Limited for New Zealand. It is offered to the FTR Working Group to assist it with the development of the FTR proposal.

Our analysis has been confined to a consideration of various publicly-available materials published by Transpower on the FTRs proposed for New Zealand, and a number of directly relevant academic articles on the subject. We have not, for example, conducted an extensive review of the available academic, industry and regulatory literature on FTRs and the associated electricity transmission system issues to which they are addressed, and nor have we investigated the relatively limited international experience of FTRs to date. Neither have we considered the likely effects of the proposed FTRs on any particular participants in the New Zealand electricity sector.

In summary, we find that:

- 1) FTRs offer some hedging benefits against inter-nodal price (transmission constraint and loss rental) variation, but these benefits are limited, in the main, due to FTRs short duration and constrained coverage of grid capacity. These features in turn arise from the requirement that FTRs are self-funding (i.e. “revenue adequate”). In general the self-funding requirement is not a necessary feature of instruments that provide hedging benefits against internodal price variation, and hence the limitations associated with FTRs are themselves not necessary. The allocation of FTRs is to be made through bidding for an existing “pool of funds” – FTR payments are tied to available transmission constraint and loss rentals – which will induce rapid take-up and this may to some degree inhibit the development of close substitutes. The FTRs are not close substitutes for long term risk instruments.
- 2) While FTRs can help to “discover” the market value of transmission constraint and loss rentals - a feature that should assist with new transmission investment formation - this additional information will be limited by their short duration, and by any divergences of FTR prices from the expected present value of transmission constraint and loss rentals.
- 3) FTRs can help to mitigate, but not eliminate, “free-riding” issues associated with new transmission investment on interconnected grids, and may also under certain circumstances reduce incentives for detrimental grid modifications (although under Transpower’s proposal this could be materially strengthened).

- 4) Depending on the circumstances FTRs may either enhance or mitigate any issues of market power, and where they affect strategic choices and behaviour (which issues become more pronounced in the light of certain features of the proposed FTR auction) they will also affect bidding in the energy and reserves market, thereby influencing transmission constraint and loss rentals themselves. As with other hedge instruments that are readily available – e.g. through a secondary market – they can be used by participants to profit from private information not held by others.
- 5) Finally, by virtue of their self-funding nature FTRs may give the appearance of requiring little or no risk premium (relative to that of alternative third-party hedging instruments), but any such appearance must be seen in the light of their limitations and some uncompensated risk borne by the current recipients of transmission constraint and loss rentals that their revenues might sufficiently fall on average with the introduction of FTRs that their welfare is reduced. There is a risk that this reduction will occur, it is not a predicted outcome.

This report is structured as follows:

- 1) Section 2 – backgrounds features of the New Zealand electricity system and associated issues underlying Transpower's proposal to create FTRs, and refers to relevant international examples of FTRs or their equivalents;
- 2) Section 3 – summarises the main features of the proposed FTRs and their operation;
- 3) Section 4 – provides an economic analysis of the proposed FTRs, including an analysis of:
 - a) what effect they will have on the ability of market participants to mitigate risk and “free-riding” problems, on the resolution of uncertainty, and hence on transmission investment decisions;
 - b) how they affect the existing market power of industry players, and *vice versa*; and
 - c) the efficiency and equity implications of how they are to be auctioned and funded; and
- 4) Section 5 – concludes with an overview of FTRs

2. Background to the Proposed FTRs

2.1 New Zealand Electricity System

2.1.1 Distinguishing Features

Distinguishing features of the New Zealand electricity system include:

- 1) its heavy reliance on hydro-electric generation, with hydro on average contributing of the order of 65% of the country's electric energy (the other 35% predominantly comprising thermal generation based on energy sources such as geothermal steam, coal and natural gas);
- 2) its relatively low water storage, and hydro inflows generally not being well-matched to seasonal energy demands; and
- 3) the national transmission grid reflecting New Zealand's topography, being "sparse, long and skinny", with generation often being far from load.

The amount of hydrological generation and the absence of storage combine to yield a large volatile sector of generation. The shape of the grid renders interconnected "loop" networks, as opposed to "single line" networks, less of an issue than for grids in some other countries.

2.1.2 Structure and Ownership

Following restructuring of the sector in 1999 – coupled with the size of the market and economics of industry supply and distribution – generation is characterised by few independent generators (mainly state-owned) that are generally vertically integrated with retail energy supply companies, and a number of independent energy retailers and buying groups. Local lines companies are distinct entities in the electricity sector. The national grid remains in state ownership and has an objective of economic efficiency rather than the more standard profit objective of other State Owned Enterprises.

With much energy demand originating in the north of the country, and significant hydro capacity being in the south, the national electricity system faces significant transmission constraints and losses, which in turn are affected by changing demand and supply conditions and the many and varied factors to which these relate. Moreover, the relative lack of industry players and existence of constraints at various parts of the transmission network can give rise

to a “regionalisation” of the market for energy, with potential exacerbation of any market power at those locations.

2.1.3 Wholesale Market

Large industrial customers consume about 43% of New Zealand’s electricity. The remaining consumers use total electricity in the proportions commercial 22% and residential 35%. The wholesale electricity market therefore includes entities that are in the wholesale market themselves, and others that purchase wholesale electricity through intermediaries that tailor the product to various degrees to their customers’ needs. Retailers, for example, typically obtain electricity for sale to commercial, even industrial, customers under various contracts, and residential customers. In the wholesale market electricity can be traded through a spot market established in 1996, or by means of bilateral contracts. Approximately 80% of New Zealand’s electricity is traded through the spot market.

Although much of the total energy traded at any one time passes through the spot market, a lot of it is hedged. Various hedge contracts exist between generators and industrial and retail companies. Such contracts can be:

- 1) financial hedges – in which no physical delivery is required, but parties make payments to one another based on spot prices at particular times or nodes and notional supply quantities; or
- 2) physical hedges – involving the actual supply of energy at prices that are pre-agreed or set by reference to a pre-determined formula.

Financial hedges can be used to virtually duplicate physical contracts. Hedge contracts allow energy buyers to manage their exposure to movements in spot energy prices: they can be used to limit the price upside or downside, or fix prices, of electrical energy, and in this way virtually duplicate physical contracts.

The term of hedges is important as the “strike price” will reflect anticipated supply and demand conditions over that term. Short-term hedges – of a day, for example – if they were issued, would be struck at a level approximating the average spot price of the day. Long-term hedges – of 8 or 9 years, for example – will have a “strike price” that is approximately the expected marginal cost of new generation. This occurs because over the long term new plants can and may be built: no party is likely to offer a long-term hedge below this level, and no party is likely to accept a hedge above their expectation of this cost. Where there is a market for long-term hedges their strike prices should indicate the market’s view of the long-run marginal cost of electricity generation.

Financial hedges are written for particular amounts of electricity at particular nodes. If the hedge market were “thick” – i.e. moderately competitive – at each node of a set of nodes it can be expected that hedge strike-price differences would exist across nodes due to the transmission constraint and loss issues discussed below. If they were long-term hedges they would also estimate the marginal cost of new generation at these nodes. In such an environment, the “basis” risk attached to the general level of the spot price could be generally covered by hedging at any one of these nodes. The strike prices of these hedges will reflect network constraints as well as the likely cost of generation in the future.

The actual quantity and location of hedges, and agreements or arrangements that have the effect of hedging are not public and are unknown. It is known that little secondary hedge trading does take place in New Zealand and that most transactions are backed by an amount of energy consumed or produced. In any event, such is the extent of hedge related arrangements that exposure to the spot market is much less than the quantity of electricity that passes through it. In this sense the role of the spot market is to provide an efficient generation dispatch order for the system operator to enact, and for the pricing of residual electricity that is not covered by hedge-type arrangements including bilateral contracts.

2.1.4 Spot Market

The national spot market (the New Zealand Electricity Market, or NZEM) for electrical energy sets prices based on supply and load at various interconnected “nodes” of the grid. It seeks to provide the most economically efficient dispatch of nationally available generation in any half-hour period to meet national energy demand wherever each should reside, subject to various constraints such as system reliability. The spot market thereby seeks to ensure that resulting energy prices at each node are also economically efficient, that is they represent the short-run marginal cost of supplying energy to load at each node. It does this by taking energy (demand) bids and (supply) offers and grid constraints and solving a computable general equilibrium short-run economic model of the nodal-market (SPD). An equilibrium is struck that also clears the reserve market.

2.2 Transmission Constraints, Losses and Network Characteristics

2.2.1 Transmission Constraints

A transmission constraint refers to the capacity of the grid to carry energy from one point to another. Where demand at one point of the grid exceeds this capacity then generators

upstream of the constrained part of the grid will be unable to supply their desired capacity and, by virtue of the spot market's operating rules, higher cost generators will be required at other nodes in their place, thereby leading to increased delivered energy prices at the point of demand. The difference in the price of energy supplied upstream of the transmission constraint and the delivered price downstream of the constraint can be thought of as a "rental" to the grid operator, reflecting the scarcity of transmission capacity over the grid. Alternatively this difference can be thought of as a charge borne by the generator to have its energy delivered to load downstream of a transmission constraint.¹

2.2.2 Losses

Transmission losses are an associated concept, reflecting that any transmission grid has electrical resistance (or in the case of alternating currents, impedance), and as a consequence an amount of energy is lost when it is transmitted along that grid. The closer a section of the grid operates to its transmission capacity - i.e. its constraint - the greater the losses. Losses represent a real cost to the economy in that they are electrical energy that could be either not generated or put to other uses were it not for their consumption in transmission. In NZEM generators are paid for the energy they supply to meet losses.

Given the particular characteristics of the New Zealand electricity grid losses can take on a greater significance than they do in other transmission networks. For a given resistance, losses increase as an increasing quadratic function of the electrical energy passing through the line. SPD models them as a spline approximation and, in order to mimic a competitive market, its nodal prices include marginal losses.

2.2.3 Rentals

The difference between energy prices at any two nodes of the grid can be thought of as comprising a rental for both transmission constraints and losses.² If the system is unconstrained and losses are negligible, then spot prices at each node in the electricity system should be the same.³ To the extent that either or both of these conditions are not satisfied, significantly variable and large inter-nodal price differences can arise and they generate rentals.

¹ In a stable environment with little demand response there is some debate as to whether the congestion rentals are enjoyed by the grid or generators that are upstream of the constraint. See Rassenti *et al.* (2000).

² To the extent that higher-cost alternative generation is available to satisfy demand, then the effect of a transmission constraint is reflected in demand downstream of that constraint being satisfied without net additional energy being generated, but at a higher delivered energy price than if the constraint was not binding.

³ Wu *et al.* (1996) provide a counter-example to the proposition that transmission constraint and loss rentals will not arise in an unconstrained network.

The transmission constraint and loss rentals are calculated monthly in NZEM as the residual of price x quantity (off-takes) of purchasers less the aggregate of price x quantity (injections) for generators. Symbolically,

$$\text{Transmission Loss and Constraint Rentals} = \sum_{i=1}^n p_i (q_i^p - q_i^g)$$

where $i = 1, \dots, n$ nodes of the grid,

p_i is the price of electrical energy at the i th node, and

q_i^k is the quantity of electricity purchased ($k=p$) and sold ($k=g$) at node i .

The rentals thus do not include the payments to generators for the energy they supply to meet losses. However, they do include the effect of higher prices due to constraints, and rentals due to losses⁴ rising at an increasing rate with energy throughput (once throughput reaches a certain level). Marginal-loss pricing means that there is a rental generated by infra-marginal losses. SPD approximates marginal losses in determining prices. It is apparent that any factors that affect injections, off-takes and prices at nodes will affect rentals.

NZEM rules require that transmission constraint and loss rentals be paid to Transpower as the grid owner under these rules. In a separate transaction Transpower pays these rentals to the asset owners that connect with and contribute to the fixed costs of the grid (“grid-connected parties”, comprising lines companies, “direct-connects” and generators), which it does so in the form of discounted grid access charges.⁵

Allocation of transmission constraint and loss rentals to these companies is justified on the grounds that it is “intuitive” that those paying the fixed costs of the grid should receive the rentals, and that by doing so ensures efficient pricing incentives are preserved (since the payment is divorced from marginal usage decisions).⁶ In fact, the rentals obtained after the generators have been paid for the energy in the losses, given the pricing mechanism, arguably properly rest with the grid because it generated them.

Among the factors that affect supply and demand conditions (and therefore also transmission constraint and loss rentals) at each point in the grid are:

⁴ See Appendix A

⁵ Prior to 1999 much of the transmission constraint and loss rentals were passed to distribution companies as relevant asset owners. Since the government-mandated split between energy and lines in 1999 these rentals have been allocated to lines companies.

⁶ Hogan (2001), p. 18. The passing on of these rentals by Transpower to the grid-connected parties helps to ensure that it, as grid owner, faces no incentive to influence dispatch, manipulate grid configuration or inhibit network investment so as to increase transmission constraints and losses.

- 1) the price and ability of “fuel” for generation (e.g. the availability of stored and expected water flows in the case of hydro generation);
- 2) weather patterns and hence demand for energy for heating or cooling in various parts of the country;
- 3) plant availability and planned or unplanned generation and/or transmission outages; and
- 4) the demand for energy-intensive industrial output (which might, for example, be driven by changes in the exchange rate or export market economic growth rates).

Inter-nodal prices are volatile on a trading period basis and transmission constraint and loss rentals are volatile on a monthly basis. For a full year these rentals amount to approximately 5% of total spot market purchases.

2.2.4 Effects of Interconnection

To complicate matters further, a feature of any interconnected (loop) electricity system is that energy fed into one point of the transmission grid is not limited to following any particular path of the grid to reach a particular load, by virtue of its natural propensity to flow along the path of least resistance (a consequence of Kirchoff’s laws). Every injection into, and off-take from, the grid affects electrical flows at every point on that grid, and it is therefore difficult to precisely define property rights over such flows.

As a consequence, electricity market participants - generators and energy users in particular - face changing and unpredictable costs of transmission constraints and losses (as reflected in differences in the prices they face at different nodes on the grid) in response to the actions of other market participants. This gives rise to commercial risks that they may wish to mitigate, but which may be difficult to manage in the absence of clear physical property rights over electricity flows.

Additionally, any generator and/or energy consumer that invests in new transmission capacity intended to relieve a constraint along the grid cannot expect to capture all of the benefits of that additional capacity, since other generators and energy users will be able to benefit from the additional capacity (a form of free-riding). This gives rise to potential problems in securing new transmission investment.⁷

⁷ Grid investment of a loop system faces this free-riding problem as well as the standard network issue of strong scale economies.

It should be noted, however, that these interactions and related problems are not particular to the electricity system, even if the underlying causes (i.e. the physical laws relating to electricity flows across interconnected networks) are unique. Any economic system considered in “general equilibrium” terms will exhibit similar network features to various degrees. Similarly, other networks such as those for water, gas and oil will also exhibit interactions by virtue of being interconnected. Accordingly, and even though electricity can be distinguished from other typical goods markets due to the fact it cannot be stored nor switched through routes, it is likely that these particular features will be more a matter of degree than of kind. However, the degree remains controversial: see for example, Wu *et al.* (1996) and Léautier (2001).

2.3 FTRs

2.3.1 International Examples

FTRs or their equivalents have recently been created or are being considered in various interconnected electricity systems around the world to mitigate some of the issues raised by the lack of physical property rights for transmitted electricity and price variability due to transmission constraints (and to varying degrees losses) in those systems. For example:

- 1) “fixed or firm transmission rights” (i.e. also called FTRs) were introduced by the system operator for Pennsylvania, New Jersey and Maryland (PJM) in April 1999;
- 2) “transmission congestion contracts” (TCCs) were introduced in New York in September 1999; and
- 3) “financial congestion rights” (FCRs) are to be introduced in New England in December 2001.

Each of these instruments is a purely financial right conferring on its holder the right to receive from (or indeed an obligation to pay to) the FTR coordinator an amount based on:

- 1) the difference in electricity spot prices between two given nodes in the electricity network;
- 2) a defined quantity of electrical energy (as opposed to actual electrical flows); and
- 3) a given period of time.

2.3.2 Defining Feature

A defining feature of these rights is that after network transactions have concluded payments are made to (or by) the FTR holders, funded by transmission constraint and loss rentals. Thus a supplier between two nodes incurs the cost of transmission constraint and loss rentals but if it holds an FTR for that particular level of supply it is paid the amount of this cost, and is thereby insulated from these rentals, or inter-nodal price differences.

The, so-called “FTRs” in California are not a similar instrument, since they are not tied to rentals generated through nodal price differences.

2.3.3 Purpose

FTRs are intended to:

- 1) assist their holders in mitigating or “hedging” the commercial risks associated with variable and unpredictable price variations due to transmission constraints and losses; and
- 2) encourage new transmission investment by providing:
 - a) financial equivalents to physical capacity rights, thereby mitigating free-rider problems associated with new transmission investment;
 - b) an observable measure - in terms of their own market price - of the expected long-term price of such transmission constraints and losses, which in turn should assist in new transmission investment decisions; and
 - c) depending on the FTR framework adopted, a potential source of funding – from the sale of new FTRs over transmission investments – that can be applied to such new investments.

2.3.4 Purchasers/holders

FTRs can be allocated to interested parties - the most natural candidates being energy purchasers and generators - by any number of means. These include:

- 1) in PJM most FTRs are allocated by formula to those paying transmission charges for access to the grid, with the balance being auctioned; and
- 2) in New York they are auctioned to the highest bidders, with auction revenues being allocated so as to reduce transmission charges, akin to the general treatment of transmission constraint and loss rentals in the absence of FTRs.

In this regard it is noted that financial institutions have also acquired FTRs in the PJM market.

FTRs may be formally tradeable on secondary markets, or where no such formal provision is made, informally traded,⁸ or made effectively tradeable by suitable combinations of purchases and sales of energy.⁹

2.3.5 Funding

Prior to the introduction of FTRs, grid-connected parties receive an allocation of transmission constraint and loss rentals, whereas after the introduction of FTRs they forego some or all of this allocation. In the latter case they receive instead either:

- 1) FTRs that provide them with whatever benefits such instruments offer (and perhaps some auction revenue); or
- 2) an allocation of FTR auction proceeds and an allocation of any residual rentals.

It is predicted that the FTR auction proceeds will not only be less variable than the congestion and loss rentals, but that they should be expected to be of the same value.¹⁰

Since FTR payments are to be funded by transmission constraint and loss rentals, thereby requiring no additional outlay of funds by electricity market participants, it is also suggested that they can therefore be offered at no financial risk to the system operator.¹¹ It is alternatively suggested that they can be offered at a "low risk premium". In each case it is suggested that they would not otherwise be possible, since any other means of funding FTR

⁸ Along the lines noted in Stoft (1997), p. 2.

⁹ Cardell *et al.* (1997), footnote 11, p. 122.

¹⁰ Transpower (2001h).

¹¹ Hogan (2001), p. 23. This presumably means aside from the risk of it bearing the transaction costs of offering FTRs in the event that they are not purchased.

payments would require third party involvement without the benefit of access to the transmission constraint and loss rental pool.¹²

2.3.6 Coordination – Revenue Adequacy and Simultaneous Feasibility

To ensure that all FTR payments can be funded by transmission constraint and loss rentals (i.e. “revenue adequacy”) it is necessary to ensure that the FTRs issued and/or sold are defined in accordance with the characteristics of the electricity network, meeting certain technical requirements guaranteeing “simultaneous feasibility”. We note that general energy hedge contracts (as opposed to FTRs) are not subject to such requirements.

Simultaneous feasibility requires testing whether or not the net injections and off-take under a proposed set of FTRs would be dispatchable on the grid irrespective of the location of generation and load.¹³ In simple terms this requires the physical grid to have a capacity at least as great as that assumed in the definition of the set of FTRs.

Since this test requires knowledge and access to models of the grid, the task of ensuring these requirements are met generally lies with the system operator. If FTRs are to be auctioned then the task of running the auction also tends to lie with the system operator. In principle it is possible, however, for these responsibilities to be assumed by any other competent party, but it would require that party to have unimpeded and up-to-date access to the relevant pricing model of the grid and its inputs.

The result that simultaneous feasibility guarantees revenue adequacy can be compromised by either unplanned outages or changes in relevant market rules. It may also be compromised if extra constraints are imposed on the operation of the grid to ensure electricity quality or if other contingent events arise in the actual grid that are not modelled by the system operator (or FTR operator if different to the system operator). Furthermore, Philpott and Pritchard (2001) note that simultaneous feasibility does not guarantee revenue adequacy if losses are quadratic or piece-wise linear, or if there are negative nodal prices (which can arise with positive offer prices due to the “spring-washer effect” of electricity networks).¹⁴

In these cases transmission constraint and loss rentals may not cover required payments under existing FTRs, and hence FTR payments would need to be reduced to ensure FTR payments need no additional funding. Alternatively, in anticipation of such events the fraction of the capacity of the systems for which FTRs are issued could be restricted (limiting the

¹² Transpower (2000), slide 9.

¹³ And satisfying all thermal limits, and all voltage, stability and contingency constraints. Bushnell and Stoft (1996).

¹⁴ The possibility of negative nodal prices is also confirmed by Wu *et al.* (1996).

amount of FTRs that can be made available). Under either approach FTRs cannot provide complete cover against nodal price differences for the entire capacity of the grid.

Since there are a number of reasons why revenue adequacy cannot be guaranteed, revenue inadequacy – of some degree or materiality – may be expected.

2.3.7 Predicted Economic Features

By creating a financial property right FTRs are predicted to perform a number of functions in relation to risk cover, investment and price signals.

FTRs are intended to provide a financial equivalent to perfectly tradeable physical trading rights. In conjunction with energy hedge contracts struck at an appropriate level, suitable FTRs can result in the “economic equivalent of a long-term contract for specific power delivered to a specific customer”.¹⁵ As such the difficulties arising in the context of an interconnected system (and the physical properties of electricity on such systems) can be mitigated.

Subject to two important caveats, FTRs are predicted to provide the requisite property rights and pricing certainty for transmission network investment. However, despite FTRs, free-riding can continue to occur because of network effects arising from the fact that in a loop network an increase in capacity in one segment will increase the capacity of all segments. Also, grid capacity investments typically must be implemented in large discrete amounts and have significant economies of scale that complicate pricing and cost recovery. Furthermore, FTRs cannot be used to effectively allocate the sunk costs of any existing grid with open access.¹⁶

With these caveats in mind, it is predicted that FTRs will facilitate investment in transmission capacity by allowing investors to be financially neutral if additional capacity they create to alleviate a transmission constraint is put back into constraint by the action of other parties connected to the grid, as might happen even with efficient investment in capacity. This would be achieved by the investor being issued or sold new FTRs over such additional capacity. These investors could also be allocated the revenues from the sale of the new FTRs as a means of funding the investment. Furthermore, by indicating the market value of the transmission constraints and losses over the life of the FTR, these instruments are predicted to provide useful signals for future transmission investment.

¹⁵ Hogan (2001), p. 23. Joskow *et al.* (2000) note that this result arises with competitive energy and rights markets (p. 457).

¹⁶ Hogan (2001), p. 25.

Importantly, since FTRs - like financial energy hedge contracts - are set by reference to notional supply quantities as opposed to actual energy levels supplied, they are predicted to provide a hedge against price volatility without distorting the spot electricity price, thereby leaving it to efficiently distribute electricity from generators to load.

Bushnell and Stoft (1996) emphasise the complementarity of the inter-nodal price hedging of FTRs and other hedge instruments, such as CFDs, for reducing price-level risk in transmitting across the grid.

Finally, another predicted consequence of FTRs is that they, unlike other hedging instruments such as options are consistent with a “hub and spoke” decomposition of the actual grid with the result that most price differences of long-distance transmission can be captured without distortion in a reduced number of special or aggregated nodes (“hubs”). Basing activity around such hubs can have the benefit of relieving issues relating to thin markets at each node, thereby mitigating potential issues of market power.¹⁷ In New Zealand hubs could be established at a variety of locations: for example, Auckland (Otago), Wellington (Haywards) and the South Island (Benmore).

3. FTRs Proposed for the New Zealand Electricity System

3.1 Main Features

Sharing much in common with FTRs in operation or proposed in other electricity networks, the FTRs proposed for New Zealand by Transpower are to:

- 1) have a duration of one month (where each month is comprised of days divided into half-hour trading periods, and FTR payments are determined by reference to spot prices at particular relevant nodes and a contract amount for each of those periods);
- 2) be offered on the core grid, but it has not yet been determined whether they will also be made available on spur lines (transmission constraint and loss rentals on spur lines would be allocated to grid-connected parties in the current fashion if FTRs are not offered on those lines);
- 3) be sold by auction, without reservation prices, just prior to the month to which they relate (but may be auctioned some time earlier than that, creating a forward market for FTRs);

- 4) be available for purchase by any party, but are expected to be of most value to generators and energy purchasers (non-market participants would be permitted to acquire FTRs subject to unspecified prudential requirements); and
- 5) be freely tradeable on a secondary market.

Furthermore:

- 1) to facilitate transmission investment new monthly FTRs will be assigned to investors in transmission capacity, subject to periodic reviews/reconfigurations, for the duration of the investment, with a capacity set equal to the incremental network capacity created by the investment (which will in general differ from the rated, or “name-plate”, capacity of the investment), and with the investor being able to nominate which nodes it would like the FTR to cover or even decline the FTRs (e.g. if they dislike the possibility of having to make payments under the FTRs; in this case the new FTRs would be offered at large by auction);
- 2) FTR auction revenues, and any residual transmission constraint and loss rentals, are to be allocated to the grid-connected parties that are currently allocated the rentals by means of a reduction in Transpower’s revenue requirement and allocation of the reduced revenue requirement to the grid-connected parties in the usual fashion;
- 3) to the extent that transmission constraint and loss rentals are insufficient to cover FTR payments (e.g. due to unplanned outages compromising revenue adequacy), those FTR payments will be down-scaled *pro-rata*;
- 4) because losses are more of an issue with the particular characteristics of New Zealand’s electricity network than they are overseas:
 - a) “spot injection FTRs” are to be sold by the auction (at a negative price - i.e. being paid for by the auction - since they require the holder to assume a financial obligation for the injection of extra energy to make up for losses); and
 - b) “directional FTRs” are also to be issued under which the contracted energy amount at the injection node is greater than that at the off-take node, the difference being the allowance for losses.¹⁸

¹⁷ Hogan (2001), p. 23.

¹⁸ Transpower (2000), slide 14, estimates that spot FTRs might represent 5 – 10% of the total value of FTRs.

Various details have also been provided regarding how the auction is to be conducted, information disclosures, and for contracting, settlement and credit risk management. Of note are:

- 1) FTR operating costs are to be borne by the auction participants in the form of a monthly levy based on auction revenues;
- 2) FTR set-up costs are to be equally borne by Transpower and the auction participants, with payment from the latter being included in the monthly levy calculated on auction revenues (until the set-up costs have been recovered) ; and
- 3) defaults on FTR auction sales or payments to the auction where FTRs have a negative payment are to be ultimately borne by the grid-connected parties.

Furthermore, the GST-rateability of FTRs is currently under investigation.

Regarding the FTR auction we understand that bidders for FTRs will bid price/quantity pairs that they commit to, with the successful bidders being identified through an auction revenue maximisation subject to constraints such as that of capacity. Scaling of FTR bid quantities will occur only in the event that a “tie-breaker” is required.

No details have been generally released regarding:

- 1) any tax consequences of the change from allocating transmission constraint and loss rentals to grid-connected parties to allocating them FTR auction revenues instead (and any residual rentals); or
- 2) the taxation treatment of FTR acquisition costs and payments.

On the latter point we understand from Transpower that FTR payments will be taxable, and FTR acquisition costs tax-deductible.

Transpower notes that the hedging benefits provided by FTRs will be less than complete, and suggests that private insurance “top-ups” might be acquired by parties who wish to obtain more full hedge cover.

3.2 Motivation

The two main motivations behind Transpower’s FTR proposal appear to be:

- 1) to assist generators and energy purchasers by providing them with an instrument that can be used to manage the commercial risk they face due to inter-nodal price volatility arising from transmission constraints and losses; and
- 2) to facilitate investment in transmission capacity by not only mitigating these commercial risks, but also by reducing free-riding problems and providing market-based indicators of the long-term value of transmission constraints and losses.

FTRs are seen as an efficient means by which to achieve these objectives, in that they are not predicted to distort market signals as provided by the spot electricity market. Additionally, they are not seen as exacerbating any market power held by current market participants, and they provide an efficient means of allocating transmission constraint and loss rentals.

Underpinning each of these is a belief that without the transmission constraint and loss rental funding of FTR payments, these instruments would not otherwise be made available to market participants. While private insurers could similarly offer a partial hedge product like FTRs, it is argued that they could not do so at such a “low risk premium” as that implied by the rental funding of FTR payments, and hence they would not do it at all (but for, perhaps, some top-up contracts to supplement FTRs).

Various additional uses and purposes of FTRs have been suggested, including the minimisation of market power, to increase market liquidity, to improve the grid operator’s incentives to schedule/minimise outage impacts, and to facilitate new entrants to energy markets. We note that since Transpower is to run the FTR system on a zero profit or loss basis, we would expect it to be indifferent regarding the scheduling or minimisation of outage impacts due to the introduction of FTRs.¹⁹ The other matters we discuss later.

3.3 NZEM Operational Aspects

Two matters deserve comment. The first is that, under the operating rules of the New Zealand Electricity Market certain energy measurement errors (such as those arising from metering errors) give rise to subsequent “wash-ups” in which quantities are reallocated according to the corrected data, at given prices, and revised payments and invoices issued. Such revisions can take place at unpredictable times after the errors occurred; on occasions more than a year later. Some of these wash-ups involve a re-allocation among market participants and others rectifying the original inclusion of too much or too little measured data. Thus, from the

¹⁹ Transpower is to recover a proportion of the FTR establishment costs.

definition of loss and constraint rentals, washups may increase or decrease these rentals at some unpredictable date after they were incurred.

The second issue relates to the fact that errors can affect prices in NZEM that are then used for transactions within and without NZEM. Within a very short period of dispatch, prices are deemed to be final and unable to be revised. Thus if an error is discovered - after prices are final - that would affect prices if the pricing model, SPD, were re-run eliminating the error, the prices paid by purchasers and received by generators are not the prices that would exist in the revenue-adequate dispatch of capacity. In this event, *ex post* transmission constraint and loss rentals produced by NZEM may be greater or less than the rentals that are in accord with revenue adequacy.

In both sources of error transmission constraint and loss rentals are affected.²⁰ In the case of wash-ups there remains the issue of what to do about changes in the transmission constraint and loss rentals that relate to an earlier period. Under Transpower's proposal that it operate the FTR market on a zero profit or loss basis any error-related surpluses/deficits will be passed on in some way. No matter how this is done it will impart variation in payments and uncertainty relating to the FTR market, the empirical importance of which could be evaluated on the basis of historical experience and simulation. Among options for the treatment of wash-ups include that the rental overs or unders be applied:

- 1) to FTR payments at the time they are calculated, in which case uncertainty attaches to FTR ownership; or
- 2) elsewhere, such as directly to grid-connected parties or other parties without reference to their FTR holdings..

These contingencies pose uncertainty issues of an undetermined expected magnitude, and whatever approach is adopted the FTR contract will have to specify the way they are to be handled.

²⁰ There would appear to be no reason to believe that these adjustments will net out on average.

4. Economic Analysis of Proposed FTRs

4.1 Risk Management

4.1.1 Rationale

An electricity operator's decision to manage the commercial risks it faces from whatever source, like that of any other organisation, will be related to a set of interrelated factors such as that operator's:

- 1) risk preference – i.e. are they risk-neutral, risk-loving or risk-averse?;
- 2) organisational form – e.g. do they enjoy limited liability? (a matter which will naturally affect the operator's appetite for risk);
- 3) access to suitable hedge instruments at an economic price;
- 4) industry characteristics – e.g. are their operating returns subject to sudden unpredictable and/or large swings and/or sustained episodes of volatility?;
- 5) financing mix – e.g. is their balance sheet so highly geared that volatile operating returns can lead to breaches of financial covenants with funding providers and/or raise the spectre of financial distress or bankruptcy with the significant costs associated therewith?;
- 6) dividend policy – related to financing mix, e.g. do their equity capital providers prefer a secure ongoing cash payout to a risky capital gain?;
- 7) investment choices and commitments – related to both financing mix and dividend policy, e.g. if proposed investments require increased balance sheet gearing but also a secure ongoing dividend stream, then greater predictability of operating returns may be required;
- 8) tax issues – e.g. is the operator in a position to utilise tax losses arising from losses due to volatile operating returns?;
- 9) financial circumstances – e.g. an operator that is already in financial distress may prefer more volatile operating returns since this may offer it a chance to “gamble its way out of trouble”;

- 10) executive compensation arrangements – e.g. if such arrangements offer executives asymmetric returns, paying them large bonuses with good operating returns, but imposing no financial down-side with poor returns, then volatile operating returns may be preferred to secure returns; and
- 11) other liabilities – e.g. does the operator face contractual default costs and/or other potential liabilities in the face of volatile operating returns, other than those related to financial distress or bankruptcy?

Additionally, under certain circumstances (which may or may not be transitory) it may be possible for hedging instruments to be used as a means to influence market power (any benefits of which would be taken into account in formulating this decision), as discussed further in Section 4.3.

As such, an electricity operator's decision to hedge the risks confronting it from volatile nodal spot electricity prices due to transmission constraints and losses will reflect a complex combination of factors. Without first considering each of these factors and their interactions it is impossible to predict the optimal level of hedging that such an operator might wish to undertake.

However, since these factors do not all suggest a preference for stable over volatile operating returns, and because hedging arrangements are not costless, it should be expected that each electricity operator will have an optimal level of hedging, varying over time, that it might wish to undertake. Accordingly, it is reasonable to expect that there will be demand for a market, to whatever degree, for instruments that provide a hedge against volatile spot electricity prices due to transmission constraints and losses.

Whether or not such a market can and should be introduced in New Zealand will depend on:

- 1) whether the benefits of its existence outweigh the costs of its introduction and operation; and
- 2) the availability of parties willing to assume the risk off-laid by hedgers.

These questions, and whether or not FTRs are the best way to provide the desired hedge, are discussed below.

4.1.2 Hedging and FTRs

The hedging properties of FTRs depend upon their:

- 1) duration;
- 2) coverage;
- 3) symmetric treatment of nodal price differences; and
- 4) availability.

Each is discussed below.

Duration

All other things being equal, the longer the duration of a hedge or the more forward a hedge can be purchased the greater the hedging benefits it confers. Conversely, a very short-term hedge offers little by way of hedge, since its returns will closely approximate those of the underlying variable against which they are written.

The FTRs proposed for New Zealand by Transpower, like those typically offered by the PJM system operator, have a duration of one month. This is relatively short for a hedging instrument, with other examples of hedges such as options, futures and forward contracts typically being of a longer duration.

If the underlying variable against which a hedge is written is stable and stationary,²¹ then even a one-month hedge might provide an acceptable hedge duration. This is because hedges could be successively taken out so as to ensure ongoing certainty as to returns, without great variation from month to month in terms of the cost and benefits of that hedge. In this regard we note that successive one-month FTRs are to be offered under Transpower's proposal.

However, if the variable over which the hedge is written is so stable and stationary, then the value of the hedge must be relatively small, since an unhedged position would result in similar returns to a hedged position. The cost of a hedge in this case should be correspondingly small.

²¹ In the sense that the parameters of its underlying statistical distribution are stable over time.

Since FTRs are written over differences in nodal prices, it is therefore useful to consider the nature of these differences over time. Of note are:

- 1) in the past load growth has been mainly in the north of the country and significant generation capacity in the south: if, for example, this pattern was to continue, in the absence of new transmission investment to relieve existing constraints or generation investment in the north, nodal-price differences could be expected to grow with time, and hence not be stationary; and
- 2) historical nodal price differences are quite markedly variable, with very significant and sometimes sustained peaks on occasion – the very sort of volatility caused by transmission constraints and losses, and which industry operators might wish to hedge.²²

Under such circumstances it would therefore be desirable to either be able to buy FTRs well ahead of the period to which they relate (i.e. that there be a forward market for FTRs), or that FTRs be offered with durations of longer than a month. Indeed, FTRs with a duration of only one month under these circumstances would be of limited benefit for risk-management purposes. One-month FTRs offer mitigation of very short-term relative-price spikes, but not the opportunity to take a position on trends and medium term cycles in transmission constraints and losses.

In this regard we note that Transpower's FTR proposals include the possibility of auctioning FTRs forward, up to around 12 months ahead, but that doing so would be complicated due to structural uncertainties such as outage scheduling, grid investments and divestments, and changes to system dispatch rules. For precisely the same reasons it should be expected that market participants would wish to be able to hedge against these uncertainties. In the absence of forward or longer than one month hedges against nodal price differences, the hedging benefits of FTRs are likely to be limited.

The fact that prospective revenue adequacy implies some restrictions on either FTR coverage of (potential) capacity or the extent to which they offer complete cover, as the term of the FTR changes has been reviewed above. The sources of inter-nodal price risks for the long, as opposed to short, term suggest that instruments for long-term risks would be more valuable.

²² See for example Market Surveillance Committee (2001), Figure 5.

Coverage

As noted previously, there are a number of reasons why (*ex ante*) revenue adequacy cannot be guaranteed.²³ These reasons include:

- 1) unplanned outages;
- 2) changes in market rules;
- 3) the imposition of additional constraints on the grid to ensure electricity quality;
- 4) other contingent events affecting the grid which may not be modelled by the FTR operator when testing simultaneous feasibility;
- 5) quadratic or piece-wise linear losses with negative nodal prices,²⁴ and
- 6) NZEM operational issues.

To the extent that such matters are not anticipated when FTRs are auctioned and they give rise to revenue inadequacy, FTR payments will need to be down-scaled to ensure the FTR system is operated at no profit or loss. The closer revenue adequacy is met *ex post* before scaling the more the FTRs will mitigate risk for their holders.

Additionally, FTRs are written on defined power levels which cannot be expected to perfectly reflect actual generation and load over the life of the FTR. The effect of this on the risk cover offered by an FTR will depend upon a trade off between system capacity covered by FTRs and the extent to which an FTR offers complete cover.

The issues of duration and market and FTR coverage are jointly related and affected by the nature of risks through *ex ante* revenue adequacy. For example, the quantitative importance of unplanned outages for one-month FTRs will depend upon the extent of feasible system capacity that is assigned FTRs and the extent to which unpredicted events net-out within a month.²⁵ More surety on revenue adequacy for FTR holders can be obtained by reducing the proportion of system capacity for which FTRs are made available. This has the effect of enabling the FTRs that do exist to offer (virtually) complete risk cover, but at the expense of the availability of FTR risk cover for the balance of capacity. This trade-off is illustrated in a

²³ After the period of the FTR, revenue can always be made adequate by scaling the payments made.

²⁴ Pritchard (2001) notes that such losses imply that the feasible set of simultaneously feasible FTRs is not convex, in which case revenue adequacy cannot be guaranteed, in particular where nodal prices become negative.

²⁵ Nicki Crauford (pers. com.) has indicated that it would require an unforeseen outage of major proportions (e.g. longer than two days) for one-month revenue adequacy to be jeopardised.

proposal for one-month year-ahead FTRs whose availability is updated (increased) as the month approaches, by allocating more capacity to FTRs as the specified month gets closer.²⁶ One year out “complete” cover would be available for only the proportion of capacity that the FTRs represented. Over a period as long as a year there will be contingencies, such as changes in spot market rules or trends in demand, that might reasonably arise but not be forecastable and render it unlikely that if – even planned – grid capacity were fully (feasibly) allocated to FTRs that revenue adequacy would occur.

Revenue adequacy of FTRs is affected by the period to which they apply. The unforecastable events of a month, arguably, can be expected to consist of very short-term variations that will be negligible, and even net out, and allow revenue adequacy *ex post*, and hence provide *ex ante* revenue adequacy for one-month FTRs.²⁷ Within a month non-stationary trends – such as trend changes in demand growth – may have minimal implications and events such as market rule changes will be predictable and not affect revenue adequacy. But for periods longer than (say) a month these risks will be important and more difficult to forecast and thereby affect revenue adequacy if full capacity were to be (feasibly) allocated to FTRs. Thus long term FTRs, because of the requirement of revenue adequacy, would likely entail either limiting the amount of capacity that is offered as longer-term FTRs, or the extent to which they provide complete risk coverage. For these reasons longer term hedge coverage provided by FTRs will be less than complete for system capacity and/or the FTR instrument itself. As noted by Transpower it may be necessary for FTR purchasers to seek third-party top-up hedges if more complete coverage is required.

Finally we note that volatility of the auction revenue that will replace transmission constraint and loss rental payments to grid-connected parties will be reduced to the extent that intra-duration-period (proposed to be a month) volatility is reduced by the replacement of such rentals with their anticipated value, but inter-duration-period volatility will remain. At the time of each auction participants will revise their expectations based on the state of the electricity market and hence duration-period to duration-period volatility in auction revenue will remain and could be quite significant as the state of the market changes.²⁸

Symmetric Treatment of Nodal Price Differences

Since FTR payments are based on nodal price differences, it is conceivable that these differences become negative, in which case the FTR holder is required to pay this difference based on the contract amount to the FTR coordinator. While occasional negative nodal price

²⁶ Nicki Crauford pers. com.

²⁷ Indeed, they may net-out in a month when they would not do so over a week.

²⁸ That expectations about inter-nodal price differences might change considerably between months is indicated by Figure 5 in Market Surveillance Committee (2001).

differences in any half-hour trading period might be covered by positive differences in the remaining half-hour periods of the FTRs one-month life, this is not guaranteed. As such it is possible that the obligation nature of the FTR might restrict its effectiveness as a hedging tool.

Once again it is instructive to consider the nature of nodal price differences in assessing whether or not this issue is material. Historical data for nodal price differences not only shows that they can be highly volatile and exhibit very marked peaks in any short period of time, but also that nodal price differences that are on average positive for a sustained period of time can quickly become negative for a sustained period of time.²⁹ In New Zealand this can occur, for example, if flows reverse from the normal south to north direction through the inter-island HVDC link. Importantly, such turnarounds can occur within a month, implying that it is possible for FTRs to result in payment obligations being faced by their holders. This would not be the case if asymmetric hedging instruments such as options were instead employed, with the option holder receiving compensatory payments with unfavourable nodal price differences, but facing no cost (other than the already-paid option price) with favourable nodal price differences. Symmetry thus reduces the completeness of FTR risk cover, whether this is important depends on the extent and forecastability of these events.

If a party purchases an FTR to hedge nodal price differences of one sign, then it is reasonable to assume that they do so because of the adverse consequences they suffer from price differences in that direction. While it cannot be assumed that the reverse is necessarily true - i.e. that they face favourable consequences if nodal price differences turn out to be in the other direction - it is possible that this is the case. Accordingly, it is possible that the obligation nature of FTRs may not be as painful to their holders as the hedging benefits are helpful.³⁰

However, given that FTRs are to be purchased at a cost, and since reversals of nodal price differences may well be extremely difficult to predict (and hence to price when purchasing FTRs), it is likely that the obligation feature of FTRs will be an undesirable feature as a hedging tool.

The obligation nature of FTRs need not entail a net cash outlay by their holders if they also hold a contract for differences (CFD). In this case, and depending upon the availability of a CFD with a suitable term and other parameters, instances where payments are required of the FTR holder can be offset by the payments they receive under the CFD. While this possibility might require no net cash outlay of the FTR holder, it is possible that with asymmetric hedge instruments such as options they would in fact have been better off, benefiting from whatever payments are obtained under the CFD while facing no cost under the option. The question then becomes whether the higher acquisition cost of such

²⁹ See for example Market Surveillance Committee (2001), Figure 5.

³⁰ As would be expected if the FTR holder is risk averse.

asymmetric instruments is justified in terms of the risks the hedger wishes to avoid, and also whether one of the instruments is more efficiently priced than the other.³¹

Availability

Given that bidders for FTRs in the FTR auction make binding bids for price/quantity pairs, prices in some circumstances may be positive even if there is an excess supply of FTRs: that is, even if not all available FTRs are taken up. In other circumstances bidders may miss out on FTR allocations. While the auction should generally allocate the available FTRs to the parties that benefit most from FTRs, the unsuccessful bidders will generally place some value on the hedging benefits the FTR offered. Particularly, this might arise when less than the planned capacity of the system is offered as FTRs.

Accordingly it should be expected that there may be parties who would wish to hedge their exposure to transmission constraints and losses but who cannot obtain this cover – at least not from the FTR auction – by virtue of not being a successful bidder for the FTR concerned. Such parties would be forced to accept the transmission constraint and loss volatility or seek alternative cover from third-party sources, which will either:

- 1) be FTRs exchanged on a secondary market; or
- 2) be available on a more widespread basis than FTRs, a fact which would need to be weighed against the particular benefits of FTRs when assessing the latter's desirability as a hedging tool.

Other FTR allocation models – e.g. that of PJM – may have different outcomes in this regard.

Conclusion

Regarding the hedging benefits of the FTRs proposed for New Zealand we conclude:

- 1) given the characteristics of nodal electricity prices in New Zealand, it is likely that one-month FTRs auctioned just prior to the period to which they relate will be of lesser hedging value than either longer-term FTRs, or FTRs auctioned forward;

³¹ Options will be a more expensive form of hedge instrument than FTRs by virtue of their asymmetric treatment of nodal price differences and (for most) an absent revenue requirement. If an option market is of greater depth, however, it may mean that options are more efficiently priced than FTRs.

- 2) FTRs are viewed as complementary to energy hedges but their use in this regard is limited by the generally very much shorter duration for which FTRs can provide (virtually) complete cover;
- 3) FTRs may provide less than complete hedge coverage, or the fraction of the market that is covered by FTRs may be limited (more so the longer their term), in which case third-party top-up hedges may be required (assuming they are available);
- 4) the symmetric treatment of nodal price differences by FTRs, implying payment obligations on FTR holders in the event of negative nodal price differences, similarly limits the desirability of the proposed FTRs as a hedging tool; and
- 5) alternative hedging instruments may need to be considered if there is routinely unsatisfied demand for FTRs.

4.1.3 Alternative Hedging Instruments

A key and defining feature of FTRs is that FTR payments are to be made from existing transmission constraint and loss rentals, the adequacy of which is guaranteed (subject to certain caveats as outlined previously) by applying the simultaneous feasibility test when FTRs are auctioned.³² Furthermore, to the extent that these rentals prove to be inadequate to cover FTR payments, those payments are to be down-scaled *pro rata* to ensure the FTR system is operated on a zero profit or loss basis. As mentioned, this is likely to be an issue for longer term FTRs and will be affected by the fraction of system capacity that is assigned FTRs. Transpower acknowledges that FTRs offer less than perfect hedges, and hence that third-party top-up hedges may be required. Whether top-up hedges or an alternative to FTRs are assumed to be offered by third-parties, in each case these instruments cannot be assumed to be funded by transmission constraint and loss rentals.

However, such rental funding does not appear in principle to be necessary for risk instruments,³³ and given the short-term nature of FTRs and their symmetric treatment of price differences it is possible that alternative forms of hedging instrument may provide additional hedging benefits that need to be weighed against alternative methods of funding those benefits.

³² If FTRs have no effect on energy and reserve bids and offers then for the same network the introduction of FTRs should have negligible effect on the level of transmission constraints and losses.

³³ Bushnell and Stoft (1996) quote authors who have been so blunt as to describe revenue adequacy as "unnecessary and meaningless" if it is imposed simply to ensure the solvency of the FTR market operator.

In considering any interaction between FTRs and alternative instruments, the (dis)similarity of instruments is a key issue. Particularly for instruments that are close substitutes with FTRs the introduction of FTRs may directly affect the emergence of alternatives. Quite dis-similar instruments will be poor substitutes, however, and therefore the introduction of FTRs should not be expected to affect their availability significantly. The proposed FTRs will not generally be a substitute for energy-price hedges or options and their peculiar nature implies that they will not be close substitutes for long-term hedges, say of more than 6-10 months duration, of any kind. Indeed, if they could be of longer duration they would complement energy-price level risk instruments and thereby, at least not diminish, the demand for these other instruments.

The main effect then of the introduction of the proposed FTRs would appear to be on the provision of short-term internodal-price risk instruments. If these were potentially forthcoming FTRs have the advantage that the rental pool funding would render the uptake of FTRs relatively attractive. The pool provides an incentive for hedgers to bid in the FTR auction irrespective of whether superior alternative close-substitute hedging instruments might be employed. To the extent that the FTR auction is not highly competitive and/or otherwise not fully efficient, it is rational for parties to bid for an FTR in the hope of securing an excess return on their outlay. This is the case even if FTRs do not represent the best form of hedge instrument that they might otherwise choose. As such the existence of an FTR market may “crowd out” the development of close-substitute alternative hedge instruments, particularly if the total market for such instruments is small (as is the case for transmission constraint and loss hedges in the New Zealand market).

Although, they require no additional cash outlay by the industry, FTRs are not by implication costless. Some risk is borne by the grid-connected parties that are the residual claimants³⁴ of the loss and constraint rentals (a matter explored further in Section 4.5). Nevertheless, on the assumption that these claimants are prepared to make available loss and constraint rentals for this purpose, it is likely that because of this funding the development of similar risk instruments (in particular) may be inhibited in the presence of FTRs. Indeed the limitations of FTRs as risk instruments can be viewed as arising in preserving rental funding of them. It is a strength of FTRs that their risk to counterparties (the grid-connected parties) is relatively small, but it comes at the cost of their special features as risk instruments.

A variety of hedging instruments is commonly employed in other markets. These include forward, futures and options contracts to name just a few. Indeed, FTRs can be thought of as a rental-funded forward contract on the spot price of transmission constraints and losses with

³⁴ This is because they will forego the rentals under the FTR proposal, and receive instead an allocation of FTR auction revenue, and any non-FTR residual rents. Any variance in these sources of revenue – e.g a lower auction revenue than the present expected value of the rentals - under FTRs will be absorbed by the grid-connected parties.

a zero exercise price. In principle there is no reason why similar such instruments (absent the rental funding), existing or otherwise, could not be offered against nodal price differences.³⁵

As to what type of alternative hedging instrument would be most attractive to industry participants will ultimately depend on the availability of counter-parties to those instruments, and hence the price at which they can be bought and sold. Having a secondary market in such instruments would be of obvious advantage, and in each case the depth of the market for such instruments will be important. In principle asymmetric instruments such as options are probably of most advantage for hedging purposes, as they provide cover in the event of extreme nodal price differences in a given direction (implying, however, quite possibly severe consequences for the option counter-party).³⁶

A key issue is whether third-party hedges will be available for purchase by industry hedgers at an economic price: the type of instrument being a matter for market testing. If it is economic for grid-connected parties to fund FTR payments in exchange for FTR auction proceeds, then it is natural to ask why it is necessarily uneconomic for third-parties, bearing the same or similar risks, to do so for a similar level of payment, or whether there exist parties that are willing to accept perhaps greater risk and provide more general close-substitute instruments to FTRs?

Such parties will have a diversified exposure to other, offsetting risks. If such parties exist (and any market for hedge instruments requires the presence of a pool of risk-bearing counter-parties), then aside from the precise nature of the hedging instrument offered, it should be expected that these parties will be able to offer hedge instruments, *ceteris paribus*, on a more economic basis than New Zealand grid-connected parties. Indeed, grid-connected parties cannot be assumed to have a natural advantage in bearing the risk of changes in nodal-energy price differences, especially since many of them cannot also have an interest in energy under recently-legislated industry restructuring.³⁷

The possibility that third parties may be able to run the market for hedging instruments at lower cost than the FTR system operator can offer FTRs, for example due to specialisation and consequent greater expertise and/or economies of scale, cannot be dismissed, especially given that such non-FTR instruments are a natural extension of risk products of other industries and markets..

³⁵ In this regard we note that futures contracts have already been offered on spot electricity prices in New Zealand. Bushnell and Stoft (1996) refer to an argument that conventional financial instruments such as forward contracts can provide the same level of price certainty as FTRs but with less complications.

³⁶ As noted in Harvey *et al.* (1996) and Wu *et al.* (1996), simultaneous feasibility (and hence revenue adequacy) can be achieved with option-like FTRs but with more restrictive assumptions than FTRs. Also, unlike FTRs, options are not consistent with the "hub and spoke" decomposition of the grid that may be useful for alleviating market power considerations.

³⁷ FTRs are particularly useful instruments for parties transacting electrical energy.

In passing we note that hedge contracts of the various types already employed in the New Zealand electricity market may be constructed in such a way as to provide a hedge against nodal price separation due to transmission constraints and losses. All that is required is that a generator at one node to provide a delivered energy price to the customer's off-take node. In this case, however, the generator would bear any price separation due to transmission constraints and losses. And unlike pure energy hedges under which generators and energy purchasers are natural parties to bear the risks of such a hedge, the same cannot be said of generators in respect of transmission constraints and losses. Indeed, should the competitors of a generator learn that it has written a trans-nodal energy hedge it is conceivable that they might be able to adjust their own output in such a way as to bring on constraints thereby disadvantaging that party. Accordingly it would be unusual, we think, for generators to write such forms of hedge contract, and hence alternatives such as FTRs continue to merit investigation.³⁸

All of this discussion naturally begs the question as to why such third-party alternatives to FTRs have not already been offered in the New Zealand electricity industry. The short answer is that:

- 1) the New Zealand Electricity Market is in its infancy, and these developments should be expected to occur over time;
- 2) by world standards the market is relatively small - indeed, with perhaps only \$60 million in transmission constraint and loss rentals annually - meaning that a reasonable investment in design and marketing is usually required to elicit sufficient third-party (and often-times off-shore) interest in considering an investment in the industry;
- 3) the rules governing the industry have been subject to relatively frequent change, which tends to discourage such third-party investment where rule changes affect the value of their investment; and
- 4) historical international capital market experience is that derivative markets, for even highly traded and simple underlying assets (physical or financial), have only recently developed to any degree, while the markets for their underlying assets have in some cases been well-established for centuries.³⁹

³⁸ Bushnell and Stoft (1996) note that the availability of FTRs (and we note, presumably other forms of hedges against nodal price differences) encourage the development of trans-nodal energy hedges (e.g. CFDs) since they reduce the risk of price separation that generators are not naturally able to bear.

³⁹ For example, as noted by Arditti (1996, p. 3): "the general investment community became familiar with options when the Chicago Board Options Exchange was formed in 1973", whereas the assets over which those options were traded had in some cases themselves been traded for centuries. A good summary of the recent but rapid development of derivatives markets both generally and for commodities (including electricity) is provided in Weron (2000, p. 128).

If it were the case that third-party funded hedge instruments for the risks of transmission constraints and losses should reasonably be expected to have materialised by now in the New Zealand electricity industry, then it must be asked why FTRs or close substitute products have not already been instituted? FTRs, of course, require the acquiescence of the owners of the transmission constraint and loss rentals and the system operator. The others, and FTRs, entail resolution of the costs, uncertainties, informational asymmetries (or absences), institutional barriers and economies of scale that are germane to the development of any market, and it is not until the economic need is so great and/or the relevant technologies available and economic that effort is made to develop markets that provide solutions to those needs. Transmission constraint and loss hedges are no different, and involve features that make their development more problematic (though most probably not impossible) than for simpler underlying assets.

In conclusion, it would appear desirable to explore close substitute hedging instruments to FTRs, even if simply for top-up purposes, but that longer term instruments will not be close substitutes and the presence of FTRs should not inhibit their market development.

4.2 Transmission Investment

4.2.1 Introduction

A review of the comprehensive literature on investment issues as they relate to interconnected electricity networks is beyond the scope of this paper. Instead we focus on the network investment issues as identified in the FTR proposal, namely:

- 1) free-riding;
- 2) pricing signals; and
- 3) investment funding.

Each is discussed below.

4.2.2 Free-Riding

Free-riding issues arise in the context of interconnected electricity networks by virtue of electricity's indifference as to which wires it travels across to get from generation to load (but for resistance/impedance), or indeed from whose generator it is produced by to satisfy a load.

The problem in the context of transmission investment is that investment by one party to increase transmission capacity will produce benefits that are not fully captured by that party, and which will be enjoyed by other parties on the grid.

Hence, a party wishing to expand transmission capacity to mitigate nodal price separation due to transmission constraints and losses - i.e. a party with an interest in energy, whether as a generator or as a consumer - confronts the problem that others on the grid will participate in the expansion in capacity and may alter their behaviour so as to reintroduce the transmission constraints and losses that their investment was intended to alleviate: albeit at a different (lower) inter-nodal price differential (whether immediately or in the future). Such free-riding behaviour undermines the value of the investment to that party, and hence is likely to dissuade it from making that investment (or at least make the economics of the investment far more demanding).

While in economic welfare terms the investment may be warranted - even with the transmission constraints and losses reintroduced by the behaviour of others within the electricity network as a whole meeting a higher level of demand with lower transmission constraints and losses - the private benefits of the investments are unlikely to be sufficient to justify a private party undertaking the investment.⁴⁰

FTRs are viewed as a way to alleviate this disincentive to private parties to undertake transmission investments where they wish to alleviate nodal price separation due to transmission constraints and losses. By allocating FTRs to such investors on the new capacity they create, they can be sure that they will enjoy a level of benefits of reduced price separation even if others do alter their behaviour, perhaps over time, in such a way as to drive the new capacity back into constraint. In this case what is required is FTRs of sufficient size and duration that the investor is able to enjoy economic returns that properly compensate them for the investment.⁴¹

In practise, due to the significant network externalities and economies of scale associated with transmission investments it is possibly unlikely that even an investor with FTRs allocated to them to mitigate free-riding will sufficiently alleviate any investment disincentives. In this

⁴⁰ Ironically, things are not always this way. Hogan (1999b) records examples where perverse incentives can lead to inefficient transmission investment, reducing effective capacity on the network and as a consequence, total welfare. The most trivial example being a one-line network with a high cost generator in the importing region faced with an incentive to build a weak line in parallel to the existing line, reducing the overall flows that can be sent down the line by lower cost generators in the exporting region (by virtue of the physics of parallel lines), and thereby increasing its own flows and profits. More complex strategies can be employed to similar ends in loop networks. Hogan cites the results of other authors that under certain circumstances the existence of FTRs may alleviate such perverse incentives.

⁴¹ Indeed, it is likely that under the proposed FTRs what is being envisaged is that a party wishing to expand transmission capacity would contract with Transpower to undertake the expansion on their behalf, with their funding, in exchange for commitments to provide FTRs of sufficient size and duration to enable them to capture enough of the benefits of the expansion to warrant their funding of it.

case either the transmission investment may not economic to be undertaken in any event,⁴² or it requires a consortium of others, perhaps consisting of all potential grid users, with sufficiently allied interests to internalise the externality and undertake the investment.

Under the proposed FTRs any investors in new capacity would be offered (but not obliged to accept) a succession of one-month FTRs for the life of the investment, between nodes of their choosing, and for the incremental capacity created by the investment. It should be noted that the incremental capacity is not simply the rated capacity of the investment, but will be defined as the change in the maximum possible FTR that can be issued between the selected nodes both before and after the investment (which defines a feasible new FTR, but not necessarily an optimum feasible new FTR). Various rules are also provided for reconfiguring such FTRs over time, and for their sale by auction if the investor does not wish to accept the allocated FTR.

In this regard we note:

- 1) to the extent that transmission investments are uneconomic by virtue of free-riding issues (i.e. they cannot be justified in terms of only the interconnection fees that the transmission investor would secure on the investment), then the proposed FTR allocations should be expected to go some way towards reducing this investment disincentive;
- 2) since the allocated new FTRs are additional to existing FTRs and for the incremental capacity of the investment, the quantity of FTRs that can be offered in the usual course of the balance of the network should be unaffected, albeit they will now be expected to provide lower overall payments by virtue of the lowering of network-wide transmission constraints and losses due to the new investment;
- 3) even if other parties should change their behaviour to reintroduce the transmission constraints and losses alleviated by the investment, the investor is protected to a degree from the effects of this because they receive FTR payments in compensation (or avoid transmission constraint and loss rentals on their FTR) – in any event an overall welfare gain has been enjoyed by the network due to greater flows and lower-priced transmission constraints and losses; and

⁴² An alternative is for the transmission investment to be undertaken on such a basis that the investor can control (on a regulated basis that is) the extent to which the new capacity is deployed. In this way it can regulate the rate at which transmission constraints and losses are reduced. If the investor is allocated a suitable FTR to immunise it against the associated transmission constraint and loss costs, it can then augment its interconnection fees by arbitraging energy through the spot market across the constraint. As the market size grows and/or it requires less such returns to pay for the investment, the remaining capacity can then be deployed.

- 4) to allocate FTRs for the incremental capacity created by the investment for the investment's life may in some cases be too generous an allocation (implying a wealth transfer from those ultimately funding FTRs - in this case grid-connected parties - to the investor, in that it may be possible for the investor to recoup sufficient returns from the investment – in terms of both fixed interconnection fees and any variable fee (which are likely maximised if the new capacity is driven into constraint) and reduced nodal price separation due to transmission constraints and losses (either directly or via FTR payments) – on a lower FTR capacity and/or for FTRs of a shorter duration than the project life.

Indeed, the latter point highlights the fact that while FTRs may be useful in mitigating free-rider problems and therefore encourage welfare-enhancing investments by allowing private investors to internalise the benefits and costs of their investment, they are one element of the decision and do not of themselves solve the interconnected-grid efficient investment decision problem. This is graphically explored further in Appendix A. Further, as we review below, the incentives for strategic use of FTRs are considerably affected by the way they are allocated and this may be relevant to the design of their use as an investment device.

The mechanics of allocating new FTRs to parties making modifications to the grid raise especially important issues, in particular regarding:

- 1) what allocation rule should be used; and
- 2) do FTRs provide incentives for detrimental grid modifications, and if so, how can these incentives be alleviated.

The proposed allocation rule – allocating a new FTR for the change in grid capacity before and after the grid modification (which is unlikely to equal the name-plate capacity of the modification) – has been termed a “two-node rule” by Philpott and Pritchard (2001). They note alternative allocation rules such as the “full constraint rule” under which any combination of FTRs available before the modification should still be available afterwards, and that discussed in Bushnell and Stoft (1996), which they refer to as the “existing FTR rule”, under which any new FTRs combined with existing FTRs are simultaneously feasible.

The nature of the allocation rule poses important consequences for grid modification incentives and the effects of such modifications on other grid users.⁴³ For example, Philpott and Pritchard (2001) show that under the two-node rule in a three node grid it is possible for a grid modifier to be allocated a new FTR while at the same time diminishing the FTR quantity

⁴³ Bushnell and Stoft (1996) note that network configuration considerations alone cannot be used to determine whether grid modifications are beneficial or detrimental, and hence that regulatory input continues to be required for electricity grid modifications.

that can be awarded across other nodes in the grid. Furthermore, Bushnell and Stoft (1996) prove that so long as all FTRs match optimal dispatch, then new FTRs allocated according to the existing FTR rule to a party making a detrimental grid modification will have a negative value at least as great in magnitude as the loss in welfare from that modification.

Bushnell and Stoft note that even this result does not provide complete protection against detrimental grid modifications (indeed, such protection would require strict conditions which they hesitate to invoke). Under these conditions it is still possible for a party making detrimental grid modifications to secure sufficient gains in the spot market and on existing FTRs that outweigh any negative value on the new FTR (an extreme case being where that party owned all existing FTRs).

These authors, like Philpott and Pritchard, furthermore state the need for the grid modifier to be obliged to assume the new FTRs so allocated. If this were not the case then the grid modifier could avoid the negative FTR value and thereby enjoy private benefits from its modifications while avoiding their associated welfare costs. Obliging grid modifiers to accept the new FTRs relating to their modifications is therefore an important means by which detrimental such modifications may be deterred. We note that this is at variance with the proposed two-node new FTR allocation rule, in which grid modifiers will have the option of declining the new FTR created on the incremental capacity of their modification.

Bushnell and Stoft also note that FTRs, when held in conjunction with CFDs, provide a measure of immunisation to grid participants from detrimental grid modifications by other parties, but that this immunisation arises in “ideal circumstances”.

While revenue adequacy is of itself not a necessary condition for hedge instruments against transmission constraints and losses, and indeed its imposition restricts the scope and availability of such instruments, in this context it can be seen to provide additional benefits. Arising, as it does, from a simultaneous feasibility test means that the application of this test can be a useful means to defining allowable new FTRs to grid modifiers. This suggests a potential trade-off between the hedging benefits offered under simultaneously feasible FTRs, and the new FTR allocation rule benefits that the feasibility requirement provides.

This discussion implicitly relies on the fact that the property rights attached to FTRs exist by virtue of rules by which the grid is operated. FTRs can be purchased and issued, but their property-right status and terms and conditions exist only with agreement at issuance and the ability to enforce them. This rests with the governance structure of the grid.

Importantly, the terms and conditions of new FTRs ought to be determined and applied prior to the investment taking place. While it is possible to adopt *ex post* review mechanisms such

as FTR reconfigurations in the light of changing circumstances (as envisaged under the proposed FTRs), there is a danger that these simply become means for an investor to secure value after the fact, possibly for investments that should never have been undertaken, rather than force the investment to stand on its merits before the fact. Alternatively, *ex post* review mechanisms may even result in investment value expropriation. Good investment incentives require commitment before the investment is executed, and clarity as to the risks confronting the investment.

4.2.3 Pricing Signals

When contemplating investment to relieve transmission constraints and losses (including whether or not such investments are required, or when they are required) it is necessary for the investor to form a view on the expected future costs of such constraints and losses. This view would then underpin an economic assessment of the benefits and costs of undertaking the investment. If that investor is limited to observing simply the actual costs of transmission constraints and losses that it bears itself, it has only a limited information base upon which to form the required view, and one which provides a similarly limited fix on what those costs should be expected to be in the future.

It is in this regard that the proposed FTRs are predicted to assist in the formulation of transmission investment plans. The existence of public auction and secondary markets for awarded FTR quantities imply FTR prices that should reflect the market's expectation as to the cost of future transmission constraints and losses, hence rendering useful information to parties contemplating transmission investment.

An alternative approach would be to conduct a statistical analysis of the nodal-price data to estimate the magnitudes of inter-nodal prices. Particularly for interconnected loop networks, calculations of differences in means is straightforward, but determining the means' confidence intervals is very difficult because of the interrelated prices across nodes and their relationships over time. FTRs should provide a direct market discovery of these price differentials. It would be of interest to assess the information they reveal and stability against the statistical approach if FTRs come to pass.

A number of caveats would appear warranted in using FTRs for price signals:

- 1) since the proposed FTRs are to have a duration of only one month, and initially at least are not to be sold forward, the incremental information provided by FTRs will be of limited value to investors contemplating transmission expansions with lives often

measured in terms of decades, especially given the likely non-stationarity in transmission constraints and losses;

- 2) to the extent that FTR auction prices measure more than just the market's expectation as to future nodal price differences due to transmission constraints and losses – for example also measuring hedging benefits in the form of avoided bankruptcy or default costs (etc) – then observed FTR auction clearing prices may in fact confound expectations as to future nodal price differences with a range of other factors, reducing their value as a source of investment signal; and
- 3) any inefficiencies in the FTR auction⁴⁴ in capturing the market's expectation as to the cost of expected future nodal price differences may also limit the value of auction clearing prices as efficient investment signals.

Hence, while the proposed FTRs may well provide better (i.e. slightly longer-term) signals of the cost of future transmission constraints and losses, these signals will be affected by any departures of FTR auction prices from the present expected value of transmission constraint and loss rentals.⁴⁵ Furthermore, these signals might be improved with FTRs of much longer duration and/or which are sold forward (e.g. up to ten years for investment signalling purposes).

We conclude this discussion of price signals by confirming the obvious point that although ideally-functioning FTRs will remove internodal price variation, the effect on prices of marginal losses will remain. Although the effect of inter-nodal price variation will be smoothed by the FTRs, the prices paid for the FTRs will reflect the effects of marginal loss pricing that is in SPD: it will not, for example, undo marginal loss pricing and produce an outcome that looks like average loss pricing.

4.2.4 Investment Funding

In this context we use the term funding to mean a contribution in any way to the expected revenue stream of capacity investment. For example it includes the expected pay-off from an FTR that has been issued to cover the incremental (FTR) capacity of new investment. The pay-off may arise from avoided transmission constraint and loss rentals yielded by that FTR.

⁴⁴ By inefficiencies in the auction is meant any auction-related matters that prevent maximisation of bidders' willingness to pay, and hence auction revenues.

⁴⁵ Note that if FTRs affect bidding the present value of expected loss and constraint rentals will itself be endogenous.

As discussed above, by allocating new investors (i.e. those with an interest in energy) FTRs, a source of investment funding is provided to the investor in the form of avoided costs of transmission constraints and losses. This funding, when added to any interconnection or other fees (or avoided costs) they would secure on their transmission investment, may make the difference between a private investor being able to capture sufficient benefits to undertake that investment, or not. Whether or not FTRs provide an efficient form of funding in this regard is a matter that would need to be considered on a case-by-case basis, and in the light of the features of the particular FTRs allocated. Hence it is possible that the proposed allocation of new FTRs for the incremental capacity and duration of any new investment may, in certain circumstances, encourage welfare-enhancing investments but in an inefficient manner, or possibly facilitate inefficient investments.

It is possible, however, that the allocation of new FTRs might provide an additional source of investment funding even if the investment is small relative to the size of the transmission market and hence has negligible impact on nodal price separation. While the investment does not therefore alleviate transmission constraints and losses to any significant degree, the investment may still be welfare-enhancing by virtue of increasing energy flows and capacity, and hence be warranted. In general, however, it will normally be the case that if energy flows increase then inter-nodal prices will fall.⁴⁶

In this case, and unlike the previous case, the investor need not have an interest in energy - either as generator or energy purchaser - to benefit from the investment. Rather they can use the allocated new FTR to protect them against the costs of transmission constraints and losses, and arbitrage energy in the spot market to generate the returns needed, in addition to the interconnection fees it can charge on the investment, to fund that investment.⁴⁷ The same efficiency caveats would apply, however, under this alternative scenario.

One scenario under which the investment funding benefits of FTRs would not arise despite the welfare-enhancing nature of the investment is where the incremental system capacity of the investment is negligible and/or energy demand very price-inelastic. While the investment would benefit the electricity system by reducing losses overall, if not transmission constraints in any material way, no new FTR would be allocated to the investor to support the investment since it has yielded no incremental capacity. In this case other means would need to be considered if the investment were to be supported.

⁴⁶ This raises potential issues for holders of any long-term FTRs, the acquisition cost of which will have reflected pre-investment levels of transmission constraint and loss rentals, if the new investment was not anticipated when such FTRs were acquired.

⁴⁷ Hogan (1999b) cites the 180 MW Direct Link project connecting the Queensland and New South Wales regional markets as an example of where such an approach has been successfully adopted. Naturally the profits from such an approach are themselves uncertain.

A third way in which FTRs might be used to encourage welfare-enhancing investments that might not otherwise be undertaken is through the allocation of the auction proceeds on the new FTR supported by the investment to the investor. We note that this method is not contemplated under the proposed FTRs.

4.3 Market Power

4.3.1 Introduction

In this analysis we make no assumption as to the presence or absence of market power by generators or energy purchasers in New Zealand, and treat the system operator as neutral given the pass-through of transmission constraint and loss rentals. We simply note that significant transmission constraints and losses can arise in the New Zealand electricity system due to the country's geography and distribution of generation and load, and that a degree of regionalisation in the operation of the system has been suggested despite the national spot electricity market. As such it is possible that market power will be held at particular times, whether or not exercised, by various parties and at various points on the network.

Whether or not market power will be affected by FTRs, or indeed *vice versa*, is an important issue that requires attention, especially if it has implications for FTR system design. We discuss this matter below.

4.3.2 Effect of FTRs on Market Power

At the outset it is important to note that the exercise of market power in the context of an interconnected electricity network may take forms markedly different to that predicted for other contexts. For example, Cardell *et al.* (1997) note that instead of restricting output to increase prices and thereby maximise any market power rents, in the context of an electricity network with transmission constraints it is possible to observe a generator with market power increasing its output above the competitive market level, both raising and lowering prices at different points in the network. By so doing that generator triggers those constraints, blocks out competing generation, and raises its bid prices so as to capture transmission constraint and loss rents for itself (thereby reducing the value of FTRs).

As mentioned previously, the introduction of FTRs is consistent with a hub and spoke decomposition of the transmission grid into a simpler contractual representation about which trading can occur. To the extent that the characteristics of the physical grid and the distribution of generation and load give rise to regionalisation of the national network, FTRs

may therefore be a useful tool for improving the liquidity at such concentrations on the network, thereby helping to mitigate any market power arising therefrom.

Furthermore, Stoft (1999) notes additional ways in which FTRs might help to curb market power. Acknowledging that FTRs provide strategic value (i.e. in terms of their potential to allow increased profits not necessarily stemming from FTR payments) in addition to their earnings value (i.e. in terms of FTR payments), conditions are identified under which generators cannot capture congestion rents. Considering a one-line energy market, if excess transmission capacity is less than the capacity of the largest generator then generators will be able to bid up their prices and thereby capture transmission constraint and loss rents (reducing the value of FTRs).⁴⁸ Conversely, however, if transmission capacity is greater than the capacity of the largest generator then FTRs will attain their full value and preclude generators from capturing the associated rents by bidding up prices.

On a less favourable note, Joskow *et al.* (2000) conclude that FTRs in fact will worsen problems of market power under a range of network, market structure and market power assumptions, a conclusion supported by Cardell *et al.* (1997). Setting aside uncertainty, and hence focusing on the market power-related impacts of FTRs rather than their hedging effects, Joskow *et al.* find that economic welfare is reduced by the introduction of FTRs by providing those with market power - whether generators or purchasers - an extra degree of freedom to exploit that power.

Starting with a single line system, these authors find that the possession of FTRs by a generator in an importing region, or a consumer in an exporting region, aggravates their market power by giving them an extra incentive to curtail their output or demand respectively, to increase their returns under the FTRs. Conversely, however, FTRs held by a monopsony in an importing region mitigate its market power by giving it an incentive to raise its price in that region.⁴⁹ Finally, possession of FTRs by a monopolist in an exporting region may have no impact on market power, since that monopolist already has the potential to capture transmission constraint and loss rents (as identified by Stoft (1999), under certain conditions).

Joskow *et al.* find these results to be generally robust when extended to a three-line loop network.⁵⁰ However, the effect on market power is affected by ownership of the FTRs and the method by which ownership is assigned. Interestingly, they explore assignment via the auction method proposed for New Zealand's FTRs and find that, although bidding strategies

⁴⁸ In an uncertain world these scenarios are considerably affected by the extent of energy hedges. Indeed, Philpott and Pritchard (2001) show that a large generator with a competitive fringe upstream of a constraint on a single line grid finds its incentives to raise prices reduced by its ownership of an FTR, an effect which they liken to that of a hedge contract.

⁴⁹ Notice that this is a case where the introduction of FTRs would affect transmission constraint and loss rentals.

⁵⁰ Similarly Philpott and Pritchard (2001) find that a large generator in a loop network can face incentives to raise prices so as to increase their FTR returns.

become complex, there remains some market power attached the existence of FTRs in certain circumstances. Their pessimistic predictions regarding the worsening of market power would need to be considered under the addition of uncertainty⁵¹, which should give rise to welfare gains in the form of hedging benefits (however big or small) and which are also likely to mitigate market power.⁵²

They find that under certain scenarios parties may be prepared to rationally over-bid for FTRs in that they secure benefits over and above the direct FTR payments. For example, a consumers' coalition at the off-take side of a transmission constraint could out-bid generators with market power for the FTRs since the cost of doing so is outweighed by the deadweight loss arising if the generators instead secure the FTRs and use them to enhance their market power.

It is axiomatic that to the extent that FTRs affect bidding behaviour via their market power influence, nodal prices, and transmission constraint and loss rentals, will also be affected by them.

In summary, there are conceivable circumstances under which FTRs can be useful for both worsening and mitigating market power. They cannot therefore be said to only mitigate market power, and as such the proposed FTRs may require further consideration in the light of particular circumstances if market power is thought to be an issue in those cases. We note that these potential problems may not be confined to FTRs, but may also arise with the availability of alternative forms of hedging instrument.

4.3.3 Effect of Market Power on FTRs

There are two apparent means by which the existence of market power may impact upon FTRs, and in particular their value and the revenues arising from their sale by auction. They are:

- 1) the exercise of market power by generators to raise supplied energy prices (thereby allowing them to capture transmission constraint and loss rentals and hence reducing FTR payments, as identified above), or by buyers to lower prices (also reducing FTR payments) – in each case distorting nodal price differences as a measure of

⁵¹ This reference to uncertainty assumes that there is no asymmetric information: which issue is discussed below.

⁵² Joskow *et al.* identify that a monopolist in the exporting region may not be able to capture transmission constraint and loss rents under uncertainty. Furthermore, if the monopolist faced a competitive fringe, or was instead a dominant generator among a number of generators, it is clearly a different proposition for that generator to attempt to invoke a transmission constraint and bid up prices so as to increase its FTR payments from a situation in which it cannot be sure to achieve this end.

transmission constraint and loss rentals attributable to scarce transmission resources;
and

- 2) the inability of the FTR auction to fully capture the value of FTRs to bidders by virtue of their market power being reflected in FTR auction bidding.

The former has been addressed already. The latter, as also alluded to above, can arise - once again depending on the particular circumstances - if for example a party with market power can systematically out-bid competitors for FTRs in the FTR auction. In that case the FTR auction revenues derived for that FTR will reflect the effective illiquidity of the market for that FTR, implying a possible wealth transfer from grid-connected parties to the FTR purchaser, a subject explored further below.

What might be considered a special case of market power as it affects the FTR auction is the issue of asymmetric information. Of particular relevance is the situation in which a party that is acquiring an FTR is planning a significant outage of which other FTR acquirors are not aware. That party, knowing that transmission constraints and losses are going to be greater than anticipated by other parties means it can afford to make higher bids at auction for the relevant FTRs than those other parties. Furthermore, knowing confidently that it can outbid those other parties at the auction means that it faces less competitive pressure to bid as much of the FTR value as it might do otherwise, thereby diminishing the resulting auction proceeds (relative to true value of the FTR), and/or discouraging FTR auction participation by other parties with the same result. The existence of competitive secondary markets in FTRs imply that an entity with relevant private information can choose at any time when to purchase a profitable FTR.

It is possible, but generally likely to be irrational, for such a party to deliberately create or draw out outages so as to secure higher FTR payments, since the associated energy market losses it sustains by doing so would probably swamp any benefits. Furthermore, to the extent that a party with such informational advantages engages in such a practice repeatedly, other parties will factor this in to their FTR bids, and sections of the Commerce Act might apply to this behaviour were it observed. Similarly, if there is more than one such party of sufficient size and/or with sufficient resources that it is so able to affect FTR payments then not only will other parties allow for such "surprise" outages in their FTR bids, but the certainty of return from such a strategy would be diminished. Nevertheless asymmetric information may enable wealth transfers, and if it affects resource decisions will affect economic efficiency. It is noteworthy that risk instruments other than FTRs may also have this property.

4.4 Wealth Effects and the FTR Auction

4.4.1 Current Rental Allocations

For the purposes of this report we have not inquired into the current formula used for allocating transmission constraint and loss rentals to grid-connected parties. Moreover, we are not in a position to comment on the economic efficiency of this allocation formula, or indeed whether allocating these rentals to grid-connected parties is the most appropriate use to which these funds may be put (and hence whether any wealth transfers arising under the FTR proposal are more or less efficient than the current rental allocations).

We simply note that:

- 1) retention of these rentals by the system operator - in this case Transpower - would likely give rise to incentives to distort grid investment and system operation decisions so as to maximise these rentals: hence Transpower's current practise of distributing these rentals to grid-connected parties;⁵³
- 2) whatever the existing rental allocation formula might be, it sets the benchmark against which any alternative allocations of FTR auction proceeds and/or residual rentals are assessed; and
- 3) it would be advisable to specify the ownership of transmission constraint and loss rentals for the efficient management of FTRs, particularly if there is any uncertainty regarding the ongoing payment of these monies to grid-connected parties.

4.4.2 FTR Auction Proceeds versus Transmission Constraint and Loss Rentals

Predicted Characteristics of FTR Auction Revenues

Transpower predicts that under its proposed FTRs:

- 1) FTR auction revenue should be expected to be the same as transmission constraint and loss rentals; and
- 2) this revenue should be less variable than the rentals.

⁵³ All allocations have some sort of incentive effects, but we do not develop consideration of this complex issue.

These are important predictions, in that if they are true, then as a group (and setting aside any changes to the allocation formula) grid-connected parties are:

- 1) no worse off in expected revenue terms than under current arrangements; and
- 2) better off in the sense that their revenues should become less variable,

while at the same time the electricity industry would appear to be better off under the proposed FTRs by having access to hedges (of whatever effectiveness) against changes in nodal price differences. To the extent that there is any uncertainty regarding the ongoing payment of transmission constraint and loss rentals to grid-connected parties, the proposed FTRs may be a necessary step if those parties wish to secure ongoing access to these rentals.

We find that while grid-connected parties can most probably expect less variable revenues under the FTR proposal,⁵⁴ as a group they face a potential change in expected revenues, the magnitude of which would be difficult to forecast.

In simplest terms FTR auction revenue will depend upon:

- 1) the valuation placed on FTRs by participants in the FTR auction; and
- 2) the efficiency of the auction in extracting this value from those bidding for FTRs.

Each of these is discussed below.

FTR Valuation

In formulating a bid for an FTR, each participant in the FTR auction will take into account its subjective expectation as to:

- 1) transmission constraint and loss rentals for the nodes of interest over the life of the FTR;
- 2) the transaction costs of FTR acquisition and ownership, including auction and administration costs, and taxation;

⁵⁴ Based on auction revenues being a function of *expected* future rentals, which will be less variable than the future rentals themselves, within the duration of the FTR. Between auction dates there will be variation in auction revenue as the state of the electricity industry evolves.

- 3) any down-scaling of FTR payments due to revenue inadequacy;
- 4) FTR benefits other than expected FTR payments, such as:
 - a) avoided costs of financial distress, contractual defaults, etc; or
 - b) possible enhancement of their ability to exploit any market power that they might hold;
- 5) defaults by other parties on negative FTR payments;
- 6) the effects on the bidder of FTRs being awarded to other parties that may use such FTRs in exercising any market power they might have, whether to their detriment or their benefit (which might arise if there were opportunities for them to “free ride” on the others’ exercise of their market power); and
- 7) the time value of money, attitude to risk and the “riskiness” of FTR benefits.⁵⁵

Furthermore, bidders may face incentives to bid strategically so as to acquire FTRs, in which case emphasis may shift from the above factors to purely strategic considerations such as:

- 1) the signals imparted by values placed on FTRs by other parties;
- 2) the likely level of competition in FTR auctions; and
- 3) secondary market opportunities to on-sell FTRs at a profit.

Appendix B provides a detailed derivation of factors affecting FTR valuation, including the impact of FTR taxation and, interestingly, FTR auction efficiency, on the value of FTRs. The latter impact arises because tax on FTRs is affected by the efficiency of the FTR auction.

As shown in the appendix, in general we can say the following:

- 1) whether or not the introduction of FTRs will lead to increased, unchanged or decreased expected revenues to grid-connected parties (i.e. whether expected FTR auction proceeds will differ from expected transmission constraint and loss rentals) will depend on complex conditions (as specified by equations (10) and (13), of Appendix B, for fully

⁵⁵ We do not specify the precise nature of the riskiness that will be priced in the FTR auction, simply noting that FTRs carry risk that will bear a cost, and that economic models such as the capital asset pricing model (“CAPM”) and arbitrage pricing theory (“APT”) provide rationales for the pricing of only certain forms of risk in equilibrium (allowing, for example, that risks that can be diversified away at small cost will not be priced).

efficient and less-than-fully efficient FTR auctions respectively) admitting countless possible scenarios; and

- 2) in the ideal situation where the FTR auction is fully efficient and/or FTR revenues and costs are not subject to taxation, not only are FTR values maximised but the revenue to grid-connected parties from that auction would also be maximised (albeit those revenues may still be expected to be greater than, equal to, or less than expected transmission constraint and loss rentals).

As shown in Appendix B, whether or not FTR auction proceeds will exceed, equal or fall short of expected transmission constraint and loss rentals will depend on a complex combination of factors such as expected: FTR payments, FTR hedging benefits, FTR market power benefits, FTR transaction costs (including FTR set-up and operating cost apportionments), FTR acquisition costs, revenue inadequacies, wash-ups, FTR payment defaults, FTR acquisition payment defaults, FTR auction (in)efficiency and FTR taxation.

Some of these factors will be relatively certain (such as set-up cost apportionments), whereas others will be highly uncertain (such as wash-ups). Some might be expected to be transitory (such as the hedging benefits of avoided bankruptcy costs, or the benefits of market power), whereas others will persist (such as FTR payments, given ongoing transmission constraints and the physical nature of the grid). Also, some of these factors may be very large, whereas others might be insignificant (such as sporadic revenue inadequacies due to normal outages). In many cases, of course, these factors may be interrelated, further complicating the *a priori* assessment of FTR valuation and the wealth effects of the proposed FTRs on the grid-connected parties that currently enjoy receive transmission constraint and loss rentals.

Auction Efficiency

Auction design is important because small differences in auction rules can have significant effects on outcomes. The proposed auction is of the “pay-as-bid” form. Comparisons between it and uniform-price auctions – i.e. the type used in NZEM’s SPD – are discussed in the context of electricity markets by Kahn *et al.* (2001) and Henney (2001). In more formal analyses, Federico and Rahman (2001) argue that the outcomes of the two auctions differ, and Léautier (2001) demonstrates that the use of either auction in the presence of private relevant information yields different outcomes in electricity markets because of electricity transmission characteristics, than they do in other markets. Since FTRs are consistent with electricity network flow properties, it is likely that the same issues apply to auctioning FTRs as to energy at nodes.

Whether or not the FTR auction will effectively capture the benefits and costs of the proposed FTRs will depend on factors such as:

- 1) auction design – i.e. will the FTR auction, in a cost-effective and timely manner, elicit bids representing the true willingness to pay of bidders for FTRs, or encourage strategic bidding based on factors other than bidders' true willingness to pay?;
- 2) market power – parties that can use FTRs to enhance their market power may be able to afford to out-bid other parties seeking the same FTRs, and may be able to do so at less than the true cost of those FTRs; and
- 3) the depth of bidding at each node – with few bidders for FTRs over particular nodes it is possible that bidding pressure at the FTR auction may be low, with the result that FTRs might be sold for less than their true value.

Auction design is generally an important consideration when seeking to maximise auction proceeds. Indeed, the auction rules can affect these proceeds both directly and indirectly, the latter particularly in relation to how the auction rules affect bidder behaviour. The fact that the FTR auction treats both FTR price and quantity as endogenous (subject to the aggregate quantity constraint), and that the value of the FTRs being auctioned is inherently uncertain, provide further complications.

A full review of the extensive auction literature as it applies to the proposed FTR auction is beyond the scope of this paper. However, in this regard we note the following:

- 1) Philpott and Pritchard (2001), assuming that the FTR auction can scale the size of any FTR bids to maximise auction revenue, find that such revenues will not be maximised under the proposed auction rules because such scaling incentivises bidders with market power to bid less than their true FTR evaluation, since doing otherwise results in them being awarded an FTR quantity less than that required for them to secure the value of their market power – a matter which they suggest could be remedied by allowing for conditional bids (in which some bids are conditional on others being accepted),⁵⁶
- 2) Philpott and Pritchard (2001) go on to question whether auction revenue maximisation might be sacrificed to ensure that parties with market power in the energy market do

⁵⁶ We note our understanding that the proposed FTR auction will not, as assumed in Philpott and Pritchard (2001), involve generalised quantity scaling unless a “tie-breaker” is required. The effects of the proposed rules vis-à-vis those assumed by these authors are not immediately apparent. While generalised scaling would appear to maximise proceeds in a one-off FTR auction, with repeated FTR auctions any over-bidding that results from such generalised scaling would lead to a change in bidder behaviour that may in fact reverse the outcome.

not secure blocks of FTRs of sufficient size to augment their ability to exercise that power, but caution that doing so might remove opportunities for FTRs to be used to diminish market power, and that the presence of a secondary FTR market would undermine any attempt to do so and simply create profit opportunities to third-parties;

- 3) it might be preferable to use a second-price auction rather than the proposed first-price ("pay-as-bid") auction, since under certain circumstances this is more likely to secure bidder's true FTR evaluations and hence maximise auction proceeds,⁵⁷
- 4) Kahn *et al.* (2001) also suggest that pay-as-bid auctions might not elicit bidders' true evaluations, arguing that they shift bidder attention from bidding what they think the asset is worth (which they are best placed to determine) to an assessment of what they need to bid so as to secure the desired asset in auction, requiring them to forecast other parties bids (which will be costly for them to do - requiring as this does an assessment of other parties' circumstances and objective functions - a cost that is disproportionately borne by smaller bidders);
- 5) as discussed previously, informational asymmetries amongst FTR bidders regarding planned outages may in certain circumstances have significant effects on the auction price of FTRs both in general, as the extra risk of non-informed parties is priced, and in specific instances where the informed party acts, suggesting that a careful consideration of disclosure rules that attend FTRs would be useful: rules that enhance information disclosure regarding, for example, planned outages over the lifetime of the FTRs under auction, would require a significant compliance regime and go to the issue of the extent to which decisions are taken by parties in a decentralised way;⁵⁸ and
- 6) defaults by FTR purchasers on making payments to the auction – whether for the FTRs themselves or for negative FTR payments – would reduce auction revenues.

Assuming bidders in the FTR auction are rational (in the sense that they will pay no more for an FTR than it is expected to be worth to them), and that negative bids will not be accepted by the auction (i.e. setting aside the acquisition of spot FTRs by the auction), it should generally be anticipated that:

- 1) at best the FTR auction should be expected to extract the true FTR valuation from FTR bidders; and

⁵⁷ This result would appear worth consideration in the light of the "winner's curse" issue identified in Philpott and Pritchard (2001).

⁵⁸ We note that these informational asymmetry issues are not peculiar to FTRs, and may arise where parties with relevant information can purchase hedges of other sorts (on primary or, particularly, secondary markets).

- 2) due to any auction inefficiencies the FTR auction might be expected to extract less than this true valuation.

This upper bound on auction efficiency stands aside from short-term possibilities of over-bidding such as those identified in Philpott and Pritchard (2001), since rational bidders in repeated auctions will modify their bids to eliminate – or at the very least minimise – the risk of overbidding. While transient over-bidding might still occur even with such a readjustment of bidding strategy, risk averse bidders will respond to the risk of this by reducing the level of their bids overall, potentially reducing auction efficiency further.

Conclusion

Whether or not FTR auction proceeds will be different from expected transmission constraint and loss rentals, affects whether grid-connected parties as a group will face a fall in expected revenues under the FTR proposal. Any premia that might be paid to acquire FTRs cannot be uniformly expected to arise (or indeed, may be only transitory in nature), will generally relate to only selected FTR purchasers at any one time, and must be weighed against the costs of the FTR system and any particular inefficiencies of the FTR auction (both of which may persist). Thus the direction of effect of FTRs on the payments to grid-connected parties rests upon competing effects and their relative magnitudes: of course, the risk to these parties being that on average these payments may fall. The volatility of payments to grid-connected parties, however, should fall somewhat with the introduction of FTRs.

4.4.3 Wealth Redistribution Effects

Other wealth redistribution effects may arise under the proposed FTRs:

- 1) as between grid-connected parties; if FTR auction proceeds (and any residual transmission constraint and loss rentals) are allocated to these entities in different proportions to those currently used to allocate rentals; or
- 2) as between other market participants – if the FTR auction captures less than the present expected value of transmission constraint and loss rental payments under each FTR.

As mentioned above, we have not inquired into the current allocation formula for transmission constraint and loss rentals, but understand that FTR auction proceeds and any residual rentals are to be allocated to grid-connected parties in the usual fashion. This should

therefore not directly give rise to wealth redistribution issues, but if this were not the case then such issues might arise.

To the extent that particular FTR purchasers are able to use FTRs to exploit existing market power, this in turn implies a wealth transfer to those purchasers from those over whom they exercise their market power.

4.5 FTR Risk Premium

It is variously suggested that FTRs as a form of hedge instrument, due to their transmission constraint and loss rental funding, can be offered at “low” or “minimal” risk premium, and that no other hedge provider could offer this.⁵⁹

In a risk-return, or mean-variance, framework we can say that grid-connected entities face a given expected level of revenue, and given level of revenue volatility, under the current arrangement by which Transpower allocates transmission constraint and loss rentals to them by way of reduced grid access charges. We can also say that the level of revenue volatility they face under FTRs should be less (however significant the reduction) than that which they currently face. The implication of the analysis in Appendix B, however, is that the grid-connected entities’ revenue under FTRs may - on average - be less than, greater than or equal to their current revenue: the issue being that we cannot predict *ex ante* the direction of change in their *expected* revenue.

Since the introduction of FTRs is predicted to reduce revenue volatility to grid-connected entities, there exists some level of expected FTR revenue, less than their *status quo* expected revenue, for which it should be predicted that the grid-connected entities enjoy the same utility (i.e. welfare) under FTRs as they do under current arrangements. We might term this their indifference level of expected FTR revenue.

The issue confronting the grid-connected entities is that a further implication of the analysis in Appendix B is that we cannot predict *ex ante* whether their FTR revenues – on average – will be greater than, less than or the same as their indifference level of expected FTR revenue either. And while it is possible that their expected FTR revenues will on average exceed this amount, it is also possible that FTR revenues will, on average, fall short of this amount – in which case implying a reduction in the grid-connected entities’ utility under FTRs, particularly if they are risk averse.

⁵⁹ See, for example, slide 9 of Transpower (2000).

The shortfall is not a predicted outcome. Rather it is an uncompensated risk for grid-connected entities' utility with the introduction of FTRs indicating that their introduction has a risk premium that might be considered relative to that of other forms of inter-nodal price hedge instrument, even though the risk would appear to be limited. Any alternative hedging instruments offered by parties other than the grid-connected entities, will be offered on an arm's-length basis without implicit funding via a risk of a reduction in their expected revenues from other quarters.

4.6 Summary

Summarising this economic analysis of the proposed FTRs:

- 1) (4.1.1) it can be expected that electricity market participants will each have an optimal level of hedging which they might wish to undertake in respect of nodal energy price differences due to transmission constraints and losses;
- 2) (4.1.2) FTRs should complement energy hedges in delivering certainty across a network, but their hedging benefits are expected to be limited, in the main due to their short duration and the fact that they will be auctioned just prior to the period to which they relate;
- 3) FTRs' hedging limitations also arise because of their limited coverage (such coverage being reduced by the risk of revenue inadequacy and NZEM operational characteristics), their symmetric treatment of nodal price differences, and their limited availability (being supply-constrained due to the need for revenue adequacy, and available only to winning bidders in the FTR auction);
- 4) while the revenue adequacy requirement of FTRs is not necessary for hedging transmission constraints and losses, and necessarily restricts their use as risk management instruments, it can – depending on the allocation rule used – be a useful way of defining new FTRs over grid modifications;
- 5) (4.1.3) it is likely to be worthwhile to consider substitute transmission constraint and loss hedges, whether provided by the industry or third-parties, because:
 - a) asymmetric hedge instruments (e.g. options) are in principle more attractive than FTRs for hedging purposes, although each might have its place given the likely difference in their costs;

- b) third-party top-up cover is likely to be required even with FTRs;
 - c) the rental funding of FTRs does not appear in principle to be a necessary feature of transmission constraint and loss hedges;
 - d) grid-connected parties cannot be assumed to have a comparative advantage in offering hedge instruments and bearing the risks they entail; and
 - e) the establishment of an FTR market may in fact restrict the development of other close-substitute third-party hedge instruments: e.g. those that might be used for top-up purposes;
- 6) complementary risk management products and long-term inter-nodal and/or energy risk instruments should be sufficiently different to FTRs that the introduction of the latter is unlikely to adversely affect their development, but for closer substitute instruments, in particular, the “bidding for a pool of funds” nature of FTRs will render them relatively attractive.
- 7) the fact that alternatives to FTRs have not already materialised may well be a reflection of the relative infancy of the New Zealand electricity system as we now know it, the frequency at which the rules of that system have been changed and, until 1999, the high concentration of generation plants: it is reasonable to expect that a market for more general risk instruments will develop;
- 8) (4.2.2) where a party with an interest in energy (as either generator or purchaser) should wish to mitigate the costs of transmission constraints and losses by investing in transmission capacity, the allocation of new FTRs to that party for the incremental capacity and life of that investment should help mitigate the disincentive it faces from other parties free-riding on the new capacity they create and reintroducing the constraints they sought to alleviate (although FTRs of themselves cannot solve the free-riding problem);
- 9) by so doing, such new FTRs can encourage welfare-enhancing transmission investments (i.e. that reduce the costs of transmission constraints and losses) that might otherwise not be undertaken due to the inability of investors to capture sufficient private benefits from that investment;
- 10) depending upon their allocation and the circumstances, however, they might not uniformly be a means of appropriately incentivising efficient new investment, and may

in some cases encourage inefficient grid modifications and/or adversely affect existing FTRs:

- a) the “two-node rule” proposed for the FTRs might be improved upon with alternatives such as the “existing FTR rule”; and
 - b) to reduce the risk of detrimental grid modifications it is important that the party undertaking those modifications be required to assume the associated new FTR, rather than simply have the option of doing so as proposed;
- 11) importantly, details regarding the allocation of new FTRs to transmission investments ought to be settled before the investment is undertaken, and subject to *ex post* review with great care, so as to ensure that investment decisions stand or fall on their merits before the fact, and inefficient investments are not unduly sustained by new FTRs (or alternatively diminished by any risk of value expropriation);
 - 12) (4.2.3) observable primary and secondary markets for FTRs should provide improved information upon which transmission investments might be instigated or undertaken, but the value of such investment signals will be limited due to the short duration of FTRs (and the fact that, initially at least, they will not be sold forward), and by any confounding due to any FTR auction inefficiencies and non-FTR payment related values ascribed to FTRs (such as hedging benefits or any market power premia);
 - 13) (4.2.4) FTRs may also assist with transmission investment by allowing parties without an energy in interest to undertake the investments with new FTRs to protect them from any transmission constraint and loss costs, and allowing them to arbitrage energy in the spot market to secure an additional source of investment funding (not that such funding would be especially certain);
 - 14) (4.3.2) there are conceivable circumstances under which FTRs can be useful for both worsening and mitigating market power, and as such rules about proposed FTRs may require further consideration in the light of particular circumstances if market power is thought to be an issue in these circumstances;
 - 15) (4.3.3) market power may also pose issues in relation to the FTR auction, resulting in possible wealth transfers from those funding FTRs (i.e. grid-connected parties) to purchasers of FTRs exercising market power, and it may affect energy bidding and hence the quantum of transmission constraint and loss rentals;

- 16) similarly, informational asymmetries may affect auction revenues and the value of FTRs, particularly in cases where parties planning outages do not disclose this information generally and therefore have an advantage in bidding for FTRs, suggesting the need to evaluate disclosure requirements and enforcement. This may affect the price of FTRs. This asymmetric- information issue also arises where, particularly secondary, markets exist in other risk instruments;
- 17) (4.4.2) unless there are very significant hedging or other non-FTR payment benefits that are valued by FTR bidders and also captured by the FTR auction, expected FTR auction proceeds, while being somewhat less variable than transmission constraint and loss rentals, may be more or less than the present value of expected rentals, implying a potential wealth transfer under the proposed FTRs;
- 18) to the extent that particular FTR purchasers are able to use FTRs to exploit existing market power, this in turn implies a wealth transfer to those purchasers from those over whom they exercise their market power;
- 19) features of the proposed FTR auction design may encourage strategic bidding behaviour, and might also not be revenue maximising (especially in the context of repeated auctions), each of which suggest careful consideration of the auction rules;
- 20) it should be expected that at best the FTR auction will capture bidders' true evaluations of the FTRs they seek (with any over-bidding being transitory, and leading to revised bidder behaviour which might reduce overall auction efficiency), and in general should be less than fully efficient; although the net effect is not predictable, it poses the risk of a fall in grid-connected parties' expected revenues; and
- 21) (4.5) FTRs can be offered at a "low" or "minimal" risk premium relative to alternative third-party hedge instruments only to the extent that FTRs risk management properties are limited and the grid-connected parties bear an uncompensated risk that their expected revenue from the FTR auction is sufficiently lower than the present expected value of transmission constraint and loss rentals that any benefit they derive from the lower revenue volatility under FTRs may be offset by this shortfall.

5. Conclusions

Trading electricity is a risky activity and instruments that enable it to be better managed while permitting de-centralised decision making will generally be in the public interest. Contemplation of the introduction of a new risk management instrument in the New Zealand

market is therefore very welcome. The sort of instrument that FTRs provide might complement longer term energy hedges and facilitate the development of trading hubs in both sorts of instruments. They address a small fraction of the element of uncertainty attaching to electricity as they provide short term cover for inter-nodal price differentials: transmission constraint and loss rentals are about 5% of electricity spot market turnover. They do not cover price level risk but FTRs of longer duration would complement energy hedges.

In the current situation transmission constraint and loss rentals produced by the national grid are paid for by the users of the grid and passed through to grid-connected parties. There is volatility in the amounts users pay and the amounts that grid-connected parties receive resulting from the concomitant volatility of inter-nodal prices. Were FTRs to be guaranteed revenue adequate *ex post*, and therefore *ex ante*, they would have the effect of eliminating the risk of this volatility for both the grid-users and the grid-connected parties.⁶⁰ It would be as if the grid users directly paid the grid-connected parties a certain amount representing the present value of expected transmission constraints and loss rentals, and the actual volatile transmission constraint and loss rental (potential) transactions were ignored by all parties: a “win-win” outcome if all parties are risk averse. There are always trade-offs however, and for FTRs they arise between the form of the cover and the nature of the risks.

Revenue adequacy is essential for the win-win outcome, and in risk environments that do not permit *ex ante* revenue adequacy attempts to maintain it will critically constrain the risk cover that FTRs can provide. Unanticipated trends, for example, imply that the *ex ante* revenue will not be adequate (i.e. met) to some extent and that either FTR payments will be adjusted accordingly, thereby reducing the risk cover that they offer, or the amount of system capacity over which FTRs are written restricted thereby reducing FTR availability. These issues arise particularly for FTRs of longer duration. In a non-stationary risky environment the possibility of *ex ante* revenue adequacy is improved by shortening the period of the cover (e.g. to one-month FTRs) or reducing the proportion of capacity available for FTRs, but it is in these environments that longer-term cover is of most utility. The *ex ante* revenue adequacy requirement generates instruments (i.e. FTRs) that are consistent with feasible interconnected (loop) network transmission but it implies restrictions on the form of the cover they provide – examples include a short length of cover and/or limited availability and symmetric obligations. Their short term cover particularly limits their usefulness in complementing energy hedges. Other risk instruments are not constrained to these characteristics.

FTRs “discover” inter-nodal prices and provide an instrument that may be used to approximate the effect of physical transmission rights (whether or not these are feasible) and

⁶⁰ Although even then allowance would need to be made for the obligation nature of FTRs, and for the risk that FTR quantities do not reflect actual levels.

thereby facilitate desirable investment in network capacity. These price signals would provide helpful information for investment appraisal although they are of such short duration in relation to the long-lived assets of grid capacity, and for various reasons may deviate from the present expected value of transmission constraint and loss rentals, that they would provide some useful input into assessing trends in inter-nodal prices as part of a wider consideration of strategic grid and generation investment by all relevant parties. FTRs are consistent with feasible transmission on the grid and, provided they are firmly committed to prior to the investment, may be used to enable decentralised capacity investment. They do not themselves solve the electricity network externality issue that enables free riding on capacity investment or provide correct investment price signals. Furthermore, while FTRs may be a useful capacity investment tool their use in this regard still requires property rights defined with respect to the governance of the grid.

Other important issues include that fact that grid-connected parties face a trade-off in that their (expected) transmission constraint and loss revenue may change (fall) as a consequence of the introduction of FTRs, but that the volatility of their revenue from this source should also fall somewhat. Whether or not they face a fair trade, in a risk-return sense, with the introduction of FTRs cannot be determined *a priori*.

Furthermore market power is potentially augmented by FTRs and affects the performance of FTRs. This latter feature may also be a possibility with other risk management instruments. Through this route FTRs may also affect spot-market bidding and therefore the level of transmission constraint and loss rentals. Under current proposals FTRs provide some scope for market participants benefitting from private information about the state of the electrical system, including their plant. This scope would also be available with other traded risk instruments.

Finally, FTRs are likely to be attractive when compared to close substitute products, because of the pool of loss and constraint rental funds that purchasers bid for and because the risk to the residual claimants – the grid-connected parties – is relatively small, although it exists. But rental funding significantly limits the scope of FTRs as risk management instruments. They are sufficiently different from long-term risk management instruments that FTRs should not be expected to inhibit the development of markets for these longer-term instruments.

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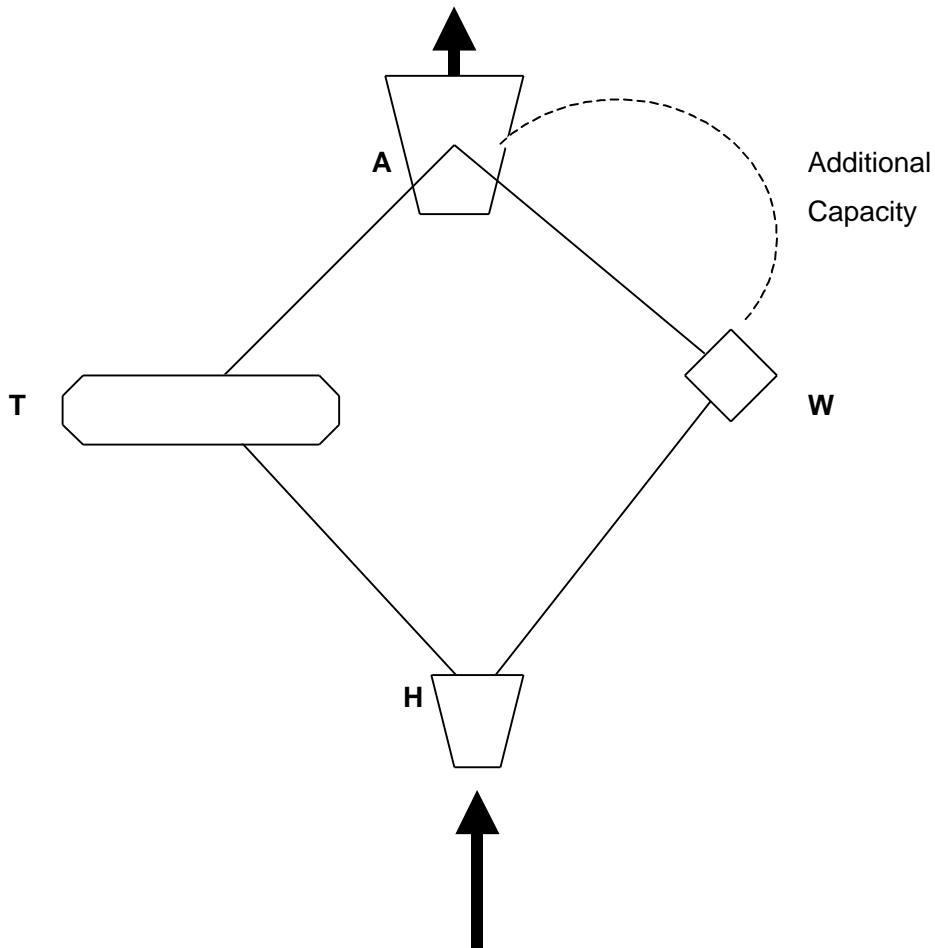
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Appendix A - FTRs and New Transmission Investment

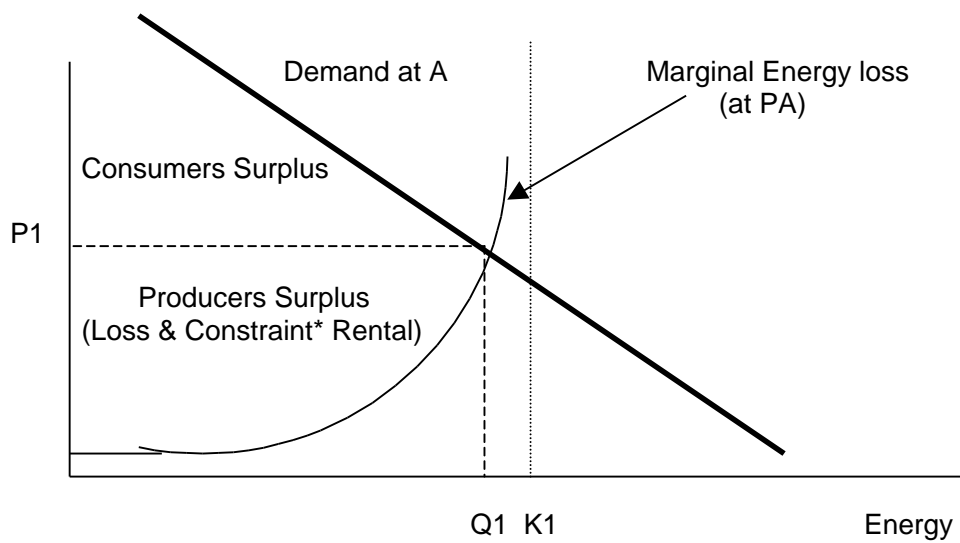
Consider the following network (setting aside constraints, but allowing for losses):



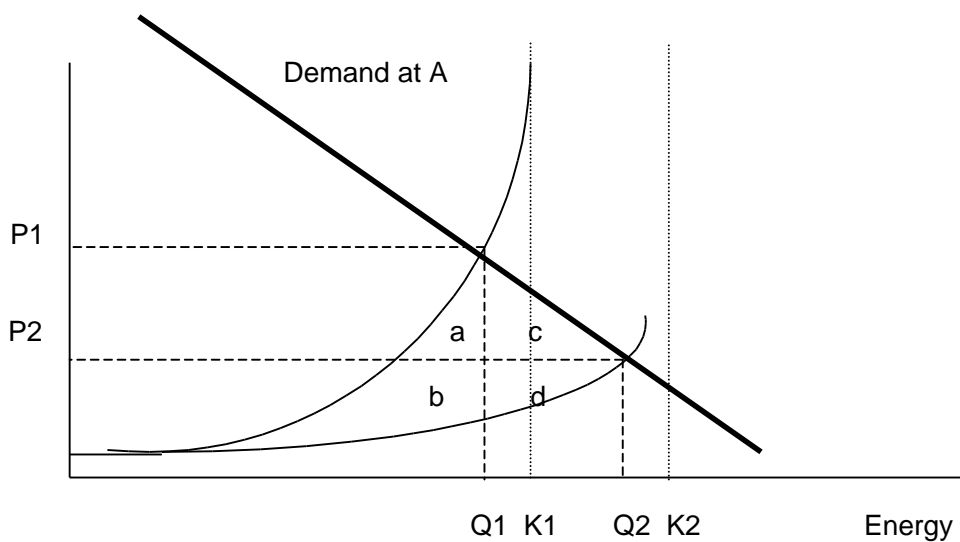
In this network energy travels northward from H through T and W to consumers north of A. The different symbols at T and W indicate different demands/supplies/resistance on these routes. Situation 1 is such that the maximum capacity between H and A is K_1 . With the addition of the capacity indicated total capacity between H and A becomes K_2 . This, Situation 2, takes account of the fact that electricity flowing through T and W will also change with additional capacity.

The NZEM energy prices at the nodes are (P_A, P_W, P_H, P_W) and the FTR price of most interest is $P_1 = P_{A1} - P_{H1}$ in situation 1. With the installation of additional capacity the price at A becomes P_{A2} and the price differential (FTR price) becomes $P_2 = P_{A2} - P_{H2}$.

Before the expansion in capacity energy flow is Q_1 and the FTR = P_1 .



* Constraint component zero in this case.



After the expansion of capacity of K_2-K_1 there is a new equilibrium of (Q_2, P_2) . The investment will be in the public interest iff:

Area $(a+b+c+d)$ annualised cost of (K_2-K_1)

The sum of a and b gives the value of energy saving (resulting from the reduction in losses at the old level of energy) of the existing quantity of transacted energy at A; whereas area c (extra consumers' surplus) plus d (extra producers' surplus) is the amount of benefit that society gains from a higher throughput at node A. Note that the energy loss is paid at the constant (in this example) price of the injection node (PH) not represented here. If demand is very inelastic the criterion will be (approximately) area $(a + b)$ annualised cost of K_2-K_1 .

Appendix B – FTR Valuation, Auction Proceeds and Rentals

1. Introduction

In this appendix we:

- 1) derive a valuation formula for FTRs;
- 2) relate this formula to FTR auction proceeds; and
- 3) identify conditions under which grid-connected parties – i.e. those who are currently allocated transmission constraint and loss rentals – can expect their revenues to rise, fall, or stay the same with the introduction of FTRs.

2. Notation

We use the following notation:

$E(.)$ = the expectation of $(.)$;

$PV(.)$ = the present value of $(.)$, which “discounts” $(.)$ for both the time value of money and the “riskiness” of $(.)$, implying that $PV(.) < (.)$;

V = the *ex ante* value of an FTR to its holder, which equates to the present value of the expected *ex post* value of the FTR (allowing for FTR benefits, costs and taxation);

A = the acquisition cost of an FTR, which equates to the auction revenue from the sale of that FTR that is ultimately allocated to grid-connected parties;

T = the corporate tax rate (i.e. 33%); and

= the “efficiency” of the FTR auction, meaning the extent to which the FTR auction captures the true valuation placed on an FTR by a bidder.

3. Complications and Simplifications

As mentioned in the body of the report, FTRs are to be awarded by auction at prices and quantities as bid by FTR bidders so as to maximise auction revenue. We understand that bid quantities will be scaled only in the event of the need for “tie-breakers”.

In the presence of market power being held by parties in the energy market it is likely that the value of any one FTR cannot be determined in isolation. This is because the exercise of market power by one party that is seeking FTRs at auction may affect other parties also seeking FTRs. As such, the prices and quantities bid by any one party are likely to reflect their expectation as to the prices and quantities bid by other parties, and any resulting impact that the success of the other parties' bids will have on their ability to exercise, or the effect on them of other parties exercising, market power.

Accordingly the valuation of FTRs should under these circumstances be considered generally and not individually. Given the complex nature of the auction clearing process (i.e. a “knapsack” optimisation involving a high-dimensionality combinatorial selection) this is unlikely to be a simple case of solving a system of simultaneous equations, even if the reaction functions of all bidders were known. In practise it should be expected that FTR bidders will employ a combination of learning and approximation to allow for these interactions.

In this appendix we do not attempt to solve for the optimum vector of FTR auction awards based on an assumed matrix of market power interactions between bidders. Instead we presuppose that such an assessment has been made by each bidder, and hence the value of an FTR to that bidder is derived as if variables such as expected FTR payments, hedge benefits and market power benefits are exogenously determined. While not providing the most comprehensive possible explanation of how FTR values are determined, this approach permits consideration of key FTR “value drivers” without involving undue complexity.

Additionally, to further simplify the analysis we focus on the valuation of an FTR as if this FTR represents the winning award in an FTR auction involving only one FTR quantity (although potentially any number of bidders for that FTR). Given the above simplification this is not at the expense of loss of generality, and once again permits concentration on key FTR value drivers.

An unrelated simplification is that we set aside the treatment of spot FTRs (which are to be paid for by the FTR auction) in our analysis of FTR acquisition costs and how they are related to FTR auction proceeds.

4. Preliminary Results

We start by reiterating certain results as identified in the body of the report, namely:

- 1) Since there are conditions under which transmission constraint and loss rentals will, aside from defaults and wash-ups, be inadequate to fully fund FTR payments:

$$E(\text{FTR payments}) < E(\text{rentals}) \quad (1)$$

- 2) Similarly, FTR payments will also fall short of transmission constraint and loss rentals to the extent there are any defaults on FTRs requiring payment to the system operator, or if there are any wash-up payments, hence:

$$E(\text{FTR payments}) = E(\text{rentals}) - E(\text{revenue inadequacy}) - \\ E(\text{FTR payment defaults}) - E(\text{wash-ups}) \quad (2)$$

where expected revenue inadequacy and FTR payment defaults are strictly positive (since none of their arguments can be negative, and each argument is positive with a non-zero probability).⁶¹

- 3) The expected benefits of owning an FTR may be summarised as:⁶²

$$E(\text{FTR benefits}) = E(\text{FTR payments}) + E(\text{hedge benefits}) + \\ E(\text{market power benefits}) \quad (3)$$

- 4) The expected costs of FTR ownership (other than FTR acquisition costs and corporate taxation, and which will be strictly positive) are:

$$E(\text{FTR costs}) = E(\text{FTR set-up cost apportionment}) + \\ E(\text{FTR operating costs apportionment}) + \\ E(\text{transaction costs of acquiring and maintaining the FTR}) \quad (4)$$

⁶¹ We assume that wash-ups will be treated asymmetrically but impose no sign on their expectation, assuming instead that on average they will not swamp the remaining variables.

⁶² In general these terms may involve interactions, but for this analysis we assume that they have been constructed so as to separate out such effects.

- 5) The expected taxation of an FTR will comprise a tax impost for any of the expected FTR benefits as and when they arise, net of expected FTR costs, and less an allowance for the acquisition cost (A, known at valuation time) of the FTR, i.e.:

$$E(\text{FTR taxation}) = T.E(\text{FTR benefits} - \text{FTR costs}) - T.A \quad (5)$$

5. General FTR Valuation Formula

From these definitions and results it immediately follows that the value of an FTR can be stated as:

$$V = PV\{ E(\text{FTR benefits} - \text{FTR costs} - \text{FTR taxation}) \} \quad (6)$$

$$= PV\{ E(\text{FTR benefits} \cdot [1-T] - \text{FTR costs} \cdot [1-T]) \} + T.A \quad \text{by (5)}$$

$$= [1-T].PV\{ E(\text{FTR benefits} - \text{FTR costs}) \} + T.A \quad (7)$$

6. FTR Auction Proceeds

Assuming, without loss of generality, that there is only one FTR to be auctioned, then the FTR acquisition cost (A), which is also the FTR auction revenue to be allocated to grid-connected parties, is given by:

$$A = .V \quad (8)$$

Assuming bidders in the FTR auction are rational (in the sense that they will certainly pay no more for an FTR than it is expected to be worth to them), and that negative bids will not be accepted by the auction (i.e. setting aside the acquisition of spot FTRs by the auction), it should generally be anticipated that $[0,1]$.⁶³ In other words, at best the FTR auction should be expected to extract the true FTR valuation from FTR bidders, and due to any auction inefficiencies (including defaults on FTR acquisition payments) it might be expected to extract less than this true valuation.

⁶³ Philpott and Pritchard (2001) identify that strategic bidders in the FTR auction may under certain circumstances over-bid for awarded FTRs (i.e. > 1). We note that this result hinges on a particular set of auction rules, and that in any case a rational strategic bidder would only so over-bid on a limited number of occasions, revising its subsequent bids to avoid overbidding. Indeed, if the auction design is such that over-bidding is a risk for any bidder, then all bidders will over time discount their bids so as to avoid over-bidding, potentially reducing overall auction revenues. A repeated auction that is efficient over time will be constructed to elicit parties' true FTR evaluations: nothing more, nothing less.

7. FTR Auction Proceeds vs Rentals

7.1 Fully Efficient FTR Auction ($\alpha = 1$)

Taking the polar case where the FTR auction is fully efficient, so that $\alpha = 1$, then $A = V$ and (7) becomes:

$$\begin{aligned} V &= [1-T].PV\{ E(\text{FTR benefits} - \text{FTR costs}) \} + T.V \\ &= PV\{ E(\text{FTR benefits} - \text{FTR costs}) \} \end{aligned} \quad (9)$$

In other words, in this case we can ignore taxation in the valuation of the FTR, and whether the FTR auction proceeds exceed, equal or fall short of the grid-connected parties' status quo (i.e. pre-FTR) revenue expectation will depend on whether:

$$PV\{ E(\text{FTR benefits} - \text{FTR costs}) \} \quad \underline{\text{exceed, equal or fall short of}} \quad PV\{ E(\text{rentals}) \}$$

which by (3) and (2) respectively can be re-stated as whether:

$$PV\{ E(\text{FTR payments}) + E(\text{hedge benefits}) + E(\text{market power benefits}) - E(\text{FTR costs}) \}$$

exceed, equal or fall short of

$$PV\{ E(\text{FTR payments}) + E(\text{revenue inadequacy}) + E(\text{FTR payment defaults}) + E(\text{wash-ups}) \}$$

or equivalently whether:

$$PV\{ E(\text{hedge benefits}) + E(\text{market power benefits}) - E(\text{FTR costs}) \}$$

exceed, equal or fall short of

$$PV\{ E(\text{revenue inadequacy}) + E(\text{FTR payment defaults}) + E(\text{wash-ups}) \} \quad (10)$$

Equation (10) therefore sets out the conditions under which grid-connected parties should anticipate a revenue increase, invariance or decrease with the introduction of FTRs, assuming a fully-efficient FTR auction. Clearly there are countless scenarios:

- 1) in the worst case, where FTRs are not expected to provide any hedge or market power benefits, then grid-connected parties can expect a fall in revenues with the introduction of FTRs (since all other terms have strictly positive expected values);

- 2) in an intermediate case such as where FTRs afford hedge and/or market power benefits, but those benefits only cover FTR costs, then this will remain the case; and
- 3) indeed, for grid-connected parties' revenue not to fall with the introduction of FTRs it is required that there be sufficient such benefits that they not only outweigh FTR costs, but they must do so to the extent that they also at least equal the combined amount of any revenue inadequacy, FTR payment defaults and wash-ups.

7.2 FTR Auction Not Fully Efficient ($0 < \alpha < 1$)

Allowing for FTR auction inefficiencies, with $0 < \alpha < 1$, it can be shown that the FTR value is given by:

$$V = [1 - T] / [1 - \alpha T] \cdot PV\{ E(\text{FTR benefits} - \text{FTR costs}) \} \quad (11)$$

where:

$$[1 - T] / [1 - \alpha T] < 1 \quad (12)$$

Comparing (11) with (9) we see that the introduction of auction inefficiencies – seemingly paradoxically – reduces the value of the FTR. This result arises because auction inefficiencies reduce the tax deduction available for the acquisition cost of the FTR, since that acquisition cost – because of the auction inefficiencies – is less than the value of the benefits (net of non-tax costs) produced by the FTR, which benefits are subject to tax.

Indeed, if we once again consider the case of a fully-efficient FTR auction ($\alpha = 1$), then since the auction now fully captures the true value of the FTR, the FTR acquisition cost is the same as the value of the benefits (net of non-tax costs) produced by the FTR, and so the tax implications of each term cancels the other.

Applying (8) with (11), we see that whether the FTR auction proceeds exceed, equal or fall short of the grid-connected parties' status quo (i.e. pre-FTR) revenue expectation will depend on whether:

$$A = \alpha V \quad \text{exceed, equal or fall short of} \quad PV\{ E(\text{rentals}) \}$$

or in other words, whether:

$$\alpha \cdot [1 - T] / [1 - \alpha T] \cdot PV\{ E(\text{FTR benefits} - \text{FTR costs}) \}$$

exceed, equal or fall short of

$$PV\{ E(\text{rentals}) \}$$

which once again by (3) and (2) respectively can be re-stated as whether:

$$\cdot [1 - T] / [1 - \cdot T] \cdot PV\{ E(\text{FTR payments}) +$$

$$E(\text{hedge benefits}) + E(\text{market power benefits}) - E(\text{FTR costs}) \}$$

exceed, equal or fall short of

$$PV\{ E(\text{FTR payments}) + E(\text{revenue inadequacy}) +$$

$$E(\text{FTR payment defaults}) + E(\text{wash-ups}) \} \tag{13}$$

In this case we are not able to reduce (13) to as simple a condition as (10), but once again we see that there are countless scenarios, leaving the grid-connected parties' revenues with the introduction of FTRs either increased, unchanged or decreased depending upon the particular circumstances.

What we can say is that the more efficient the FTR auction, and the lower the corporate tax rate, the higher is the value of FTRs and the revenues that accrue to grid-connected parties from the FTR auction.

In the trivial case where there are no expected hedge or market power benefits, no FTR payment defaults, and no wash-ups, FTR costs or revenue inadequacies, then (13) reduces to a test of whether:

$$\cdot [1 - T] / [1 - \cdot T] \cdot PV\{ E(\text{FTR payments}) \}$$

exceed, equal or fall short of

$$PV\{ E(\text{FTR payments}) \} \tag{14}$$

in which case grid-connected parties' revenues will fall with the introduction of FTRs, by virtue of (12). With no taxation ($T = 0$) this is also the case for all $\cdot < 1$ (i.e. if the FTR auction is not fully-efficient). With a fully efficient FTR auction, however, the grid-connected parties' revenues will be unchanged due to the introduction of FTRs in the absence of these other benefits and costs.

8. Conclusion

Setting aside certain complications that can arise due to market power, it is a relatively straightforward matter to derive (if not implement) a valuation formula for FTRs, and to relate FTR valuation with the proceeds of the FTR auction, allowing for both taxation and auction efficiency.

If the FTR auction is fully efficient and/or if FTR revenues and costs were not taxable, then not only would FTR values be maximised, but the revenues to grid-connected parties from that auction would also be maximised. The seemingly odd result that FTR auction efficiency affects FTR values flows from the fact that the latter benefit from a tax deduction on FTR acquisition costs, which deduction is maximised under a fully efficient FTR auction.

Whether or not the introduction of FTRs will lead to increased, unchanged or decreased revenues to grid-connected parties will depend on complex conditions admitting countless possible scenarios. The simpler of these conditions – assuming a fully efficient FTR auction – is given by (10); the more general by (13).