ELECTRICITY COMMISSION

Hedge Market Development – Issues and Options: Overview Paper

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1 EXECUTIVE SUMMARY

1. In late 2004, the Electricity Commission (Commission) formed the Hedge Market Development Steering Group (Group) to "provide advice to the Commission on the development and implementation of a transparent and liquid electricity hedge market."[1]

2. Since its formation, the Group has considered in detail the issues related to price risk management that affect the New Zealand electricity market. The Group has now made recommendations to the Commission on the initiatives the Commission should pursue to develop access to hedging opportunities among participants in the New Zealand electricity market.

3. The Group considers that its package represents a coherent strategy of mutually reinforcing components that will significantly reduce in a timely manner current problems in managing electricity price risk in New Zealand. The package is a major advance over the *status quo,* particularly in relation to disclosure of contracts and hedging locational risks in transmission pricing.

4. This *Overview* Paper outlines the Group's analysis and recommendations.

5. Access to reliable electricity supply at efficient prices is fundamental to the well-being of New Zealanders and the growth and development of the economy. Price risks are a very significant factor for participants in the New Zealand electricity market. Energy price risks arise for several reasons:

   - The range of the marginal costs of the generation plants needed to meet peak levels of demand is quite wide. Since the wholesale market encourages generators to offer at their marginal cost this means that as demand fluctuates over the course of a day and seasonally, there are material fluctuations in market prices.

   - A significant proportion of New Zealand's generation capacity is hydro-based and the availability of water to drive hydro plants can vary greatly between years. In dry-years, prices during winter can be several times the level in years with average rainfall.

   - The responsiveness of the demand for electricity to changes in prices is quite low in the short-term for very many consumers. This reflects the essential nature of electricity to many users and that it is a small proportion of total costs to many as well.

   - Outages of generating plant and transmission lines for repair whether planned or unplanned can have a very material effect on prices by altering the availability and costs of supply.

   - New Zealand's wholesale market is a nodal market which means there are different prices in each half hour at each of approximately 250 nodes. The price at each node reflects the marginal cost of supplying an

[1] Terms of Reference of the Hedge Market Development Steering Group (HMDSG).

additional unit of electricity at that node. This cost depends on the generator offers in the market, the demand at each node and the transmission constraints and losses that are incurred in meeting demand. Because of the effect of transmission constraints, prices at any one time can vary significantly between nodes and the differences are not always stable or generally predictable.

- Sometimes it is necessary to replace a cheap source of power for a major load centre with a more expensive source in order to supply an additional unit to a particular node because of transmission constraints. When this happens, the marginal cost of supply to the node, and hence the price at the node, can be well above the price of any generators offer in the market as the higher costs of providing the major load centre affect the nodal price.

- The New Zealand market is small and in some regions the number of active suppliers is low. This has raised concerns among some parties that suppliers use market power to increase prices at the expense of consumers who have not utilised adequate hedging. Whether these opportunities exist and whether suppliers have used them, if they do exist, are contentious issues and are currently the subject of a Commerce Commission investigation.

6. Hedging is the establishment by businesses and consumers of arrangements to manage the risks to their incomes or costs that they face because prices vary. The returns on a properly designed hedge will offset the effect on net revenue that occurs as a result of movements in prices. As a result, the financial position of a party with a properly designed hedge will not be changed overall by price movements.

7. Given the price risks inherent in the New Zealand electricity market, it is important that participants have access to appropriate means to manage these risks. Concerns have been repeatedly expressed since before the electricity market was started in 1996 over whether the ability to hedge is adequate.

8. The Commission established the Group in late 2004 to “provide advice to the Commission on the development and implementation of a transparent and liquid electricity hedge market”.

9. Since its formation, the Group has:

   - Established appropriate policy objectives for price risk management in the New Zealand context;

   - Identified the key problems in relation to the management of electricity price risks in this country;

   - Developed the various proposed initiatives aimed at improving the ability of market participants to manage electricity price risk;

   - Set out criteria against which to judge the proposed initiatives in terms of their ability to meet the identified objectives; and

- Evaluated the proposed initiatives against the criteria.

10. The Group distilled five key problems for electricity price risk management in New Zealand it believed its package of initiatives should address:

    - Lack of robust information about forward prices, fuel levels, planned plant outages, and so on, available to parties involved, or potentially involved, in price risk management;
    - Lack of confidence in the competitiveness of the market for term contracts;
    - Lack of a suitable instrument to manage locational-based or transmission price risks;
    - High participation and transactions costs; and
    - The general lack of understanding in the electricity market place of the advantages, techniques, and uses of price risk management.

11. The Group's preferred package of initiatives is:

    - The compulsory web-based publication of the key terms and conditions of all contracts entered into by parties that consume above a minimum level of electricity per year;
    - The Commission inviting the current owners of the web-based electricity contracts trading platform, EnergyHedge, to further develop its services;
    - Development of a mechanism to hedge AC transmission costs by changing the allocation of loss and constraint rentals;
    - Support from the Commission for the development jointly by consumers and retailers of a model master agreement for the purchase and sale of financial contracts relating to electricity;
    - Centralised web-based publication of planned outage and fuel stock information by the Commission;
    - The Commission promoting greater purchaser understanding of electricity price risk management; and
    - A regular survey of electricity market participants to ensure improvements in hedging are on track.

12. The table summarises the direct and indirect contribution of each initiative in the Group's preferred package towards resolving each of the problems. Three ticks indicate the initiative makes a large contribution to resolving the problem corresponding to the column. Two ticks indicate a moderate contribution and one tick a minor contribution.

13. It can be seen from the table that the package addresses the key problems the Group identified. With the exception of the lack of suitable instruments to deal with transmission related price risks, several of the initiatives contribute to resolving each key problem. Moreover, each initiative contributes towards resolving more than one of the key problems.

	Lack of robust information	Lack of confidence in competitiveness of market	Lack of suitable instruments to manage transmission price risks	High participation and transaction costs	Lack of understanding of risk manage-ment
Publication of contract details	✓✓✓	✓✓		✓✓	✓
Development of *EnergyHedge*	✓✓	✓✓✓		✓✓✓	
Locational Rental Allocation (LRA)	✓	✓✓	✓✓	✓✓	
Support for developing a model master agreement	✓	✓		✓✓	
Publication of outage and fuel data	✓	✓		✓	✓
Promotion of training & advisors	✓	✓			✓
Annual survey of market participants	✓✓	✓			✓
Does the package address key problems?	Yes	Yes but even better if obtain good Energy-Hedge Outcomes	Yes	Yes if good Energy-Hedge outcomes obtained	A start. Will build as experience gained

14. The membership of the Group was drawn from a wide range of backgrounds and interests. Through very open and frank debates it held a strong level of agreement on the general approach and the proposed approach was reached. In the view of the Group, the package:

- Represents a broad-based approach which should resolve relatively quickly all the risk management issues it has identified;
- Is such that, the sum of the parts will be much more effective than the individual initiatives on their own;
- Creates incentives and opportunities that will lead electricity market participants to adopt more effective risk management practices;

- Creates a dynamic of better practices by some facilitating and encouraging more widespread adoption of better practices;
- Encourages the development of further risk management opportunities by market players;
- Does not require the establishment and maintenance of a costly market to try to provide high levels of liquidity when trading volumes are likely to be modest and demand for risk management services is still uncertain;
- Does not require heavy regulatory intervention or high establishment costs and hence does not incur the risks of unintended consequences and heavy waste of resources; and
- Does not preclude recourse to other measures in the future. In any event, the package recommended by the Group would be helpful to any future scenario.

The Group is of the view that the Commission and the industry should proceed to put this package in place without delay, subject to satisfactorily developing and testing a working model of the LRA proposal.

15. After preliminary consideration of the Group’s recommendations, the Commission’s initial view is that the preferred package of the Group should be seriously considered for implementation.

16. Before making decisions on this matter, however, the Commission wishes to obtain feedback from interested parties on the proposed initiatives. Once final decisions are made on initiatives requiring rule changes, the Commission will consult on specific proposals in accordance with the requirements of the Electricity Act 1992.

17. The Commission invites submissions on both this *Overview Paper* and the accompanying *Technical Paper* including, but not limited to, answers to the specific questions contained in the final subsection of this paper by 5pm on 25 October 2006. Please note that because of the statutory-timing obligations on the Commission, submissions received after this date may not be considered.

2 INTRODUCTION

2.1 Formation and work of HMDSG

18. In late 2004, the Electricity Commission (Commission) formed the Hedge Market Development Steering Group (Group). The scope of work of the Group is to:[2]

    - Provide advice to the Commission on the development and implementation of a transparent and liquid electricity hedge market; and

    - Provide comment as necessary to advisory groups whose work affects the operation of the electricity hedge market.

19. Since its formation, the Group has:

    - Established appropriate policy objectives for price risk management in the New Zealand context;

    - Identified the key problems in relation to the management of electricity price risks in this country;

    - Developed various proposed initiatives aimed at improving the ability of market participants to manage electricity price risk;

    - Set out criteria against which to judge the proposed initiatives in terms of their ability to meet the identified objectives; and

    - Evaluated the proposed initiatives against the criteria.

20. During the course of its work, the Group considered a very wide range of issues that have been raised in relation to price risk in the context of the New Zealand electricity market. It considered questions as diverse as why there are no active brokers in the New Zealand market to what would be the consequences of synthetic separation of vertically integrated retailer-generators.

21. The Group was aided in its deliberations by receiving presentations from a number of individuals with particular areas of expertise related to price risk: John Culy (Morrison & Co), Grant Read (EGR Consulting), Brent Layton (NZIER), Tim Grafton (UMR), Nigel Williams (ANZ National Bank), Paul Quilkey (Westpac), Geoff Taylor (Taylor Duignan Barry), Mike Thomas (CRA), John Small (Covec), Conrad Edwards (Transpower), Jomar Eldoy (M-Co), Graham Shuttleworth (NERA), and Simon Coates (Contact Energy).

22. The Group was also assisted in its work by having access to the aggregated results of a survey on electricity hedging activity conducted for the Commission by UMR Research. The Group requested the survey and advised the Commission on the design of the questions and methodology. In broad

[2] Terms of Reference of the Hedge Market Development Steering Group (HMDSG).

terms, the survey demonstrated that many purchasers viewed the buying of electricity as a procurement activity and not as one involving judgements about how best to manage price risk. The survey also helped to better define what various parties considered to be the current problems they and other market participants faced in relation to price risks.

23. The membership of the Group is detailed in Appendix B. The diversity of backgrounds from which membership of the Group was drawn assisted it to identify the various facets of each issue but in the end did not preclude the Group from achieving a very high degree of consensus on the package of initiatives to recommend to the Commission.

24. The high degree of consensus emerged from working through all the issues and through developing a clear understanding of the objectives and problems and a shared view about the criteria to use to evaluate the options.

25. The Group has prepared for the Commission this *Overview Paper* and a companion *Technical Paper*. These reports outline the work the Group has undertaken and conclusions it has reached. The reports also cover the Group's recommendations to the Commission of the initiatives that should be implemented and the procedures and timelines with which this should be done.

2.2 Feedback on reports sought

26. After consideration of the Group's recommendations, the Commission's initial view is that the package of recommendations it contains should be seriously considered for implementation.

27. As a first step towards implementation, the Commission wishes to obtain feedback from stakeholders on the proposed initiatives that have been recommended. To this end, the Commission has released the document *Hedge Market Development – Issues and Options: Technical Paper*. This paper contains a detailed description, discussion, and analysis of the Group's recommendations.

28. The *Technical Paper* is necessarily detailed and very long. To facilitate receiving feedback from stakeholders and wider public understanding and involvement the Commission has simultaneously released this *Overview Paper.* It summarises the recommendations and analysis in the *Technical Paper* for the benefit of those without the time or inclination to study the full version.

2.3 Outline of the Overview Paper

29. The price risks in the New Zealand electricity market are discussed in Section 2. The role of hedging in an economy is dealt with in Section 3. The Group's view of the appropriate price risk management objectives in the New Zealand context are dealt with in Section 4. The Group's diagnosis of the key problems in relation to the efficient and effective management of electricity price risks in

this country is the subject of Section 5. Section 6 sets out the Group's criteria for evaluation of the proposed initiatives and Section 7 summarises its analysis of each and its package of recommended initiatives. The final section identifies the 'next steps' towards implementation and includes a number of discussion questions on which the Commission would appreciate receiving feedback on. There are two appendices providing respectively a glossary and membership of the Group.

3 PRICE RISKS IN THE NEW ZEALAND ELECTRICITY MARKET

3.1 Price risks very significant

30. Access to reliable electricity supply at efficient prices is fundamental to the well-being of New Zealanders and the growth and development of the economy. Price risks are a very significant factor for participants in the New Zealand electricity market. Energy price risks arise for several reasons:

- The range of the marginal costs of the generation plants needed to meet peak levels of demand is quite wide. Since the wholesale market encourages generators to be offered at their marginal cost this means that as demand fluctuates over the course of a day and seasonally, there are material fluctuations in market prices.

- A significant proportion of New Zealand's generation capacity is hydro-based and the availability of water to drive hydro plants can vary greatly between years. In dry-years, prices during winter can be several times the level in years with average rainfall reflecting the scarcity of water.

- The responsiveness of the demand for electricity to changes in prices is quite low in the short-term for very many consumers. This reflects the essential nature of electricity to many users and that it is a small proportion of total costs to many as well.

- Outages of generating plant and transmission lines for repair, whether planned or unplanned, can have a very material effect on prices by altering the availability and costs of supply.

- New Zealand's wholesale market is a nodal market which means there are different prices in each half hour at each of approximately 250 nodes. The price at each node reflects the marginal cost of supplying an additional unit of electricity at that node. This cost depends on the generator offers in the market, the demand at each node and the transmission constraints and losses that are incurred in meeting demand. Because of the effect of transmission constraints, prices at any one time can vary significantly between nodes and the differences are not always stable or generally predictable.

- Sometimes it is necessary to replace a cheap source of power for a major load centre with a more expensive source in order to supply an additional unit to a particular node because of transmission constraints.

When this happens, the marginal cost of supply to the node, and hence the price at the node, can be well above the price of any generators offer in the market as the higher costs of providing the major load centre affects the nodal price.

- The New Zealand market is small and in some regions the number of active suppliers is low. This may present opportunities for suppliers to use market power to increase prices at the expense of consumers who have not utilised adequate hedging. Whether these opportunities exist and whether suppliers have used them, if they do exist, are contentious issues and are currently the subject of a Commerce Commission investigation.

31. It is arguable that these features of the New Zealand environment, electricity system and market design result in electricity price risk being a more significant factor in New Zealand than in most economies. The events in the dry-years of 2001 and 2003 highlighted the importance of the availability of hedging for electricity price risks in the New Zealand context and raised concerns among market participants and policy makers about the adequacy of arrangements.

3.2 Political risks of dry-years

32. The events in 2001 and 2003 also reinforced in the minds of policy makers and politicians the political risks inherent in there being perceived inadequacies in the opportunities for price risk management. Dry-year risk quickly becomes a political risk when key players in the retail market are exposed to the sharp rise in prices and seem unlikely to be able to continue to deliver to consumers.

33. It is against this backdrop that the GPS issued in October 2004 places emphasis on the need to ensure market participants have the ability to efficiently and effectively manage energy prices. The same events contributed to the inclusion in the specific outcomes for the Commission laid down by legislation a requirement to seek the proper and efficient management of risks (including price risks) in relation to security of supply. Part of the Hedge Market Development Steering Group's role is to address this objective.

3.3 Locational-based price risks

34. The ability to manage locational-based price risks has also been a recurring concern. It is not just that users have paid very high prices from time to time as a result of transmission constraints, but that the difficulty of hedging these risks has restricted the entry of retailers into areas in which they do not have generation and this has compromised the level of competition in the retail

market.[3] This concern has been a longstanding one and was repeated in a recent report on New Zealand by the International Energy Association (IEA):[4]

> *A market that allowed companies to hedge locational basis risk, in particular, would help improve transparency, reduce commercial incentives for retail-generation vertical integration, reduce barriers to entry and increase competition.*

The Group agrees with the IEA.

4 HEDGING AND THE ECONOMY

4.1 What is hedging?

35. Hedging is the establishment by businesses and consumers of arrangements to manage the risks to their incomes or costs that they face because prices vary. The returns on a properly designed hedging strategy will offset the effect on net revenue that occurs as a result of movements in prices. As a result, the financial position of a party with a properly designed hedging strategy will not be materially changed overall by price movements.

36. Firms and consumers use a wide variety of techniques for, and approaches to, hedging. One common approach is to organise the business so it is not affected by price movements. The vertical integration of electricity generation and retailing is one example of this approach. Another common approach is to use purchase and sale contracts that effectively offset price risk. The purchase and sale of forward contracts are an example of this approach.

4.2 The importance of hedging to an economy

4.2.1 Allows price risks to be managed at lower cost

37. The practice of hedging does not have as its aim the stabilisation of prices. The objective is to insulate revenue or costs from price movements. Prices still vary and the consequences of this still affect the economy as a whole. What the existence of efficient and effective hedging arrangements does is to facilitate the trading of price risk so that the parties best placed to manage or bear that risk, or respond to it, are the ones that ultimately do so. In this way, the costs of the volatility of prices to the economy as a whole are minimised.

38. In the New Zealand context, one obvious example of hedging with this consequence is when a generator and a consumer enter into a fixed price term contract for a specified volume. One price risk faced by a generator is that the price of electricity will fall. In fact, if it falls below the generator's full costs, including the costs of its capital, the generator will make a loss. The wholesale market has been designed to encourage generators to offer at their marginal costs which do not include their fixed costs, and prices are set on the

[3] See *Technical Paper* Section xx for a more detailed discussion.
[4] http://www.iea.org/Textbase/npsum/NewZealand2006SUM.pdf

basis of the marginal cost of the last generator dispatched. As a result, it is not uncommon for prices in some periods and seasons to be below the full costs of many generators.

39. On the other side, a price risk faced by consumers is that prices will rise. Because of the high proportion of New Zealand's generating capacity that is hydro, there can be a shortage of electricity and exceptionally high prices when there is a year with low precipitation.

40. A fixed price term contract between a generator and a consumer is a way for these parties to off-set their risks with one another. For the volume and term covered by the contract, the generator is not exposed to prices falling and the consumer is not exposed to them rising. Wholesale prices still vary, and the consequences of dry-year risk for the economy still exist, but the counter-parties to the hedging arrangement have traded their respective risks.

41. More generally, if generators and consumers have the opportunity to choose their level of exposure to price risk by the mix of fixed or floating priced contracts they choose, then among them, the allocation of price risk will tend to minimise overall costs for bearing the risks, provided the relative prices of electricity under these different forms of contract are themselves efficient.

4.2.2 Reduce barriers to entry for potential competitors

42. If a party 'buys' now and 'sells' now it does not face any price risk from price movements because both transactions are based on the current price. Similarly, an agreement to sell something in three months at the current price at the time matched by an agreement to buy at the current price in three months time does not involve any price risk.

43. A requirement for there to be price risk is a mismatch between the time at which the 'purchase' price is set and the 'sale' price is set. This requirement is often overlooked, but it is crucial to understanding most hedging strategies, which are effectively means of removing or reducing the inter-temporal gap between setting the buying and selling prices.

44. One barrier to entry in a market in which sellers are expected to give fixed prices for future delivery can be access to fixed price purchase contracts that match the expected commitments of the sale contracts. Access to effective and efficient hedging arrangements can overcome this barrier and increase competition. It has been frequently suggested that a lack of access to effective hedging arrangements has inhibited the development of electricity retailers that are independent of generators in this country.

4.2.3 Reduces price fluctuations

45. The existence of contracts suitable for the efficient and effective hedging of energy price risks has another advantage for the efficient performance of an economy. The prices provide signals about expected prices in the future. If they have been robustly formed by the interplay of buyers and sellers, then

they can be very useful guides to those seeking to make production and consumption decisions.

46. For example, unusually high prices for electricity to be delivered and consumed six months out signal to generators that they should try to avoid scheduling outages then, and that maybe they should not mothball or dismantle a generating plant that is currently in use. Even if the generator thinks that prices may be lower by the time the period to which the forward prices relate comes around, it is still able to effectively lock in those prices now by selling forward and planning accordingly. On the other hand, forward prices can help users and consumers plan their own production and consumption activities so as to avoid periods of high prices or exploit opportunities provided by low prices.

47. Although the aim of those actively hedging is not to stabilise prices in the economy, the preceding discussion indicates that, in practice, hedging does have this effect. The forms of hedging that give rise to robust public information about expected prices in the future are particularly useful in this regard. The responses of producers and consumers to the expected prices generated by these forms of hedging have the effect of reducing the actual fluctuations in prices.

48. Producers look to increase production in periods of expected high prices, which tends to lower them, and to lower production in periods of expected low prices if they will not be economic, which tends to raise prices. Consumers have the opposite responses. The effect of the reactions of both groups is to lower the peaks in prices and raise the troughs to smooth out price fluctuations.

4.2.4 Facilitates security of supply

49. In the previous subsection we discussed the role hedging can have in reducing price fluctuations. An important variant on this in the context of electricity is that the existence of hedging and a transparent forward price curve can make a material contribution towards maintaining the security of supply.

50. When threats to supply, such as low precipitation, are perceived to have increased, forward prices will rise. The rise in prices provides a cue to parties to seek alternative sources of supply and to avoid consumption. These actions reduce demand and increase production and so contribute to maintaining supply.

4.2.5 Facilitates investment decision making

51. There is also a connection between the availability of arrangements to hedge against price risks and the long-term trend in prices, or their overall level. The objective of those that practise hedging is to insulate their own revenue or costs from price movements and, from their perspective, they are not looking to alter the overall trend in prices. However, the availability of hedging

arrangements can have an effect on investment decisions and, consequently, on actual price trends in the future.

52. Many dismiss the importance of hedging arrangements to investment decisions on the grounds that, typically, contracts for forward delivery are for 3-5 years at most but the investments will last much longer, possibly decades. This dismissal overlooks the dynamics of hedging and particularly the importance of being able to readily lock-in satisfactory returns for a period while longer-term arrangements to underpin the viability of the investment are sought and finalised.

53. One strategy used in markets for products such as gold and oil, for which there is a relatively liquid and deep market for hedging instruments, is to temporarily lock-in the returns from a proposed investment by using the market to establish a shorter-term position. This allows the investor time to look for favourable opportunities to 'roll-out' the term of the hedging arrangements by, for example, negotiating long-term forward price agreements with selected parties. As the longer term arrangements are put in place, the shorter-term hedging is reduced.

54. A market for New Zealand electricity with the level of liquidity and depth to allow the implementation of this strategy for large generation investment projects is very unlikely to develop in the foreseeable future. However, the assistance to investment decision making of effective hedging arrangements should not be completely dismissed. The ability to see the likely revenue from generation for a 3-5 year period and to lock-in revenue for moderate volumes on that basis would be a useful means of reducing risks to investors in smaller and medium-scale projects.

55. Moreover, even though a transparent forward price curve for 3-5 years may not be the perfect vehicle for hedging long-term investment projects, an upward trend in forward prices out that far can act as an important cue to parties to seek out new sources of supply, to develop demand side management opportunities, and to look for ways to conserve.

4.2.6 Allow gains from specialisation in information gathering

56. One of the side effects for an economy of having active arrangements for hedging a product or service is that it can allow specialisation in information gathering about the future demand and supply and hence the price of the commodity. This occurs if the hedging arrangements allow participation by parties above and beyond any physical involvement they may have in buying or selling the product or service.

57. Market related information can be expensive to gather and difficult to accurately analyse in terms of its likely effect on prices. Hedging arrangements that allow parties to buy and sell without necessarily taking or making delivery of the actual commodity allow specialisation in this function without the need to be involved in the physical market. This specialisation can bring efficiency gains to an economy by making the forward prices more accurate and hence

making the responses of consumers and producers and investors more appropriate.

58. Specialists in gathering and processing market information do tend to improve the robustness of the forward prices because, if they do not, they end up buying when prices are about to fall and selling when they are about to rise and losing money and the capital needed to continue to trade. On the other hand, information specialists that generally improve the robustness of forward prices tend to buy when prices are about to rise and sell when they are about to fall and so make money and are able to continue to participate in the market on an increasing scale as their capital grows. There is, therefore, a self-reinforcing dynamic; those specialists good at analysing information and forecasting future prices are able to continue to provide their skill to the economy, and those specialists that are not good at forecasting lose money and are discouraged from providing their poor predictions and may also lose the capital necessary to do so.

5 PRICE RISK MANAGEMENT OBJECTIVES

59. The terms of reference of the Group included the requirement to "provide advice to the Commission on the development and implementation of a transparent and liquid electricity hedge market."[5] A liquid market is one in which the volume of participation and level of trading is such that potential participants can trade the volumes they wish to trade without materially affecting the price.

60. The emphasis on liquidity in the terms of reference is quite understandable. A liquid market results in lower transaction costs and confidence for market participants about the ability to establish and alter positions. The level of activity in a liquid market usually also means that the prices are efficient in the sense that they incorporate all the known information about the market.

61. The Group came to the view that it may be unrealistic in the current circumstances for the relatively small New Zealand electricity market to sustain a highly liquid market for hedging electricity price risks, particularly when the level of demand for hedging arrangements is not well developed. The Group also came to the view that while a liquid market for hedging might be desirable, it is a means to an end. The end is the benefits to the economy outlined in Section 4.2 and the essential requirement is that whatever the Group recommended should optimally move New Zealand towards that end.

62. The Group agreed its primary objective should be to recommend to the Commission a package of initiatives that would collectively provide the foundation for efficient and effective price risk management among participants in the electricity market. The package should remove the blocks to the development of opportunities for hedging led by the interplay of buyers and sellers, rather than imposing mandatory requirements on market participants to contract in specified ways that do not meet their needs.

[5] Terms of Reference of the Hedge Market Development Steering Group (HMDSG).

63. The Group has rejected, at this stage, the more prescriptive proposals that various parties have put forward. This is partly because it believes the package it has put forward will achieve the objectives that are appropriate for New Zealand. It is also partly because its analysis has shown that these mandatory measures could have significant unintended side effects and impose considerable costs on participants and New Zealand. In the view of the Group, some mandatory proposals are unlikely to work, at least without an extremely prescriptive and extensive regulatory regime to monitor compliance and enforce the rules. The Group is also mindful that the level of demand for hedging services in the New Zealand context is still not clear and to adopt approaches that will entail extremely prescriptive regulatory intervention in this situation could end up imposing solutions that prove more costly than the problem and fail to meet the needs of buyers and sellers or the wider economy.

6 ELECTRICITY PRICE RISKS MANAGEMENT

64. In order to better understand the concerns of parties about price risk management arrangements and to obtain better information about the actual arrangements currently used, the Commission engaged UMR Research to survey electricity market stakeholders in 2005. The Group requested the survey and advised the Commission on the design of the survey questions and methodology. It also received the aggregated and tabulated results.[6]

65. The principal contractual arrangements in the New Zealand electricity market for household consumers and small to medium sized businesses are currently fixed priced contracts for the total volume consumed. This form of arrangement is commonly referred to as a fixed price variable volume (FPVV) contract. In short, small-scale consumers do not generally face electricity price risks, except for the risk that the fixed price in the contract they have can be raised, usually by notice from the supplier.

66. For larger-scale users of electricity, the usual arrangement is an over-the-counter (OTC), or directly negotiated bi-lateral contract with a particular supplier. The contract often provides for some certainty as to price for at least some of the volume, but may also include provisions that link current prices to historical prices. Many contracts also suspend cover in certain conditions. These conditions are often when the buyer has the greatest need for cover.

67. From consideration of the survey results and the advice it received from the experts with which it met, the Group distilled five key problems for electricity price risk management in New Zealand it believed its package of initiatives should address:

- Lack of robust information about forward prices, fuel levels, planned plant outages, and so on, available to parties involved or potentially involved in price risk management;

[6] The results of the survey can be found on the Commission's website at http://www.electricitycommission.govt.nz/pdfs/opdev/wholesale/wholesalepdfs/HedgeMarketIssues-Aug05.pdf

- Lack of confidence in the competitiveness of the market for term contracts;
- Lack of a suitable instrument to manage locational-based or transmission price risks;
- High participation and transactions costs; and
- The general lack of understanding in the electricity market place of the advantages, techniques, and uses of price risk management.

6.1 Lack of robust information

68. One of the most obvious aspects of current arrangements is the lack of timely and robust information about volumes and prices in the bi-lateral OTC contracts for electricity. For most of these contracts there is no publicly available information.

69. There is a fixed price contract index published by M-Co.[7] However, since the contracts it covers are not standardised as regards general terms, specific location, and precise term and publication is only monthly, this provides only a very coarse measure of prices and is not particularly useful for parties interested in managing price risks. There is also *EnergyHedge.* This provides a vehicle for two-way quotes out to two years for standardised contracts. The EnergyHedge framework makes no mention of unilateral suspension of obligations by either party and does not contain a force majeure provision. Currently only the major retailer-generators are participants. The market has very light trading volumes and is open only one hour per trading day.[8]

70. The availability or ease of access to information regarding fuel levels and plant outages also appears to be inadequate as it is only provided on a ‘reasonable endeavours’ basis and is not published in a form particularly useful for determining its significance for prices and hence for price risk management.

71. The paucity of information relates, therefore, not just to the actual forward prices but also to the factors which may shape them in the future. One of the essentials for the development of active trading is information about prices and the economic environment. Without a much better flow of information than at present efficient, and effective price risk management seems unlikely to develop in the New Zealand electricity sector.

6.2 Lack of confidence in competitiveness

72. There has been for sometime a lack of confidence among some consumers and regulators about the competitiveness of the OTC and wholesale markets for electricity. The Group did not take a view on whether this concern is well-

[7] For details on the method of calculation of the fixed price contract index see http://www.comitfree.co.nz/docs/FPI_Info_Sheet.doc
[8] For more information on *EnergyHedge* see http://www.energyhedge.co.nz/ePublic/mtrade.mt_public.home

founded or not but recognised that a perception that prices do not reflect robust competition can have a corrosive effect on the willingness to enter agreements and use arrangements. Parties are naturally reluctant to enter agreements when they believe the outcome can be manipulated by their counterparty to be in its favour. It does not matter whether the fear is real or imagined; it has the same effect on the willingness to trade.

6.3 Lack of instruments to manage locational-based price risk

73. The ability to manage locational-based price risks has also been a recurring concern in New Zealand It is not just that users have paid very high prices from time to time as a result of transmission constraints but concern that the difficulty of hedging prices at specific nodes has restricted the entry of retailers into areas in which they do not have generation. It is feared this has compromised the level of competition in the retail market.

74. This concern has been a longstanding one. The first attempts to address the gap by the introduction of transmission hedges by Transpower occurred over 10 years ago. This experiment was abandoned by Transpower in 1997 because it believed it carried too much risk under the arrangement. Transpower then attempted to introduce FTRs funded out of loss and constraint rentals but ran into strong opposition. Some parties objected because they did not accept loss and constraint rentals were Transpower's to use. It was also feared by some that the auction-based method of allocating FTRs incorporated in Transpower's proposal would reinforce any market dominance of retailer-generators in local areas and that FTRs would be costly and complex to administer and manage and this would limit the effective demand for and secondary trading of them.

75. The GPS of October 2004 contains quite detailed sections relating to FTRs and the Commission is required to report to the Minister on progress relating to the statement on an annual basis. We have already noted that the concern about the lack of a transmission related hedge has been repeated in a recent report on New Zealand by the International Energy Association (IEA). The Group agrees with IEA.

6.4 High participation and transaction costs

76. Another issue identified by the Group is the predominance of customised contracts. Customisation has three principal effects:

- It increases the difficulty of comparing prices and offers provided by various suppliers;

- It increases the costs for parties to reverse or reduce their contract positions as their circumstances and the risks they face change and new information arrives about future market conditions. A party wishing to change its position has to find a counterparty which is happy to accept terms consistent with those of the previous agreement. In practice, this may limit the options to trading with the original counter-party on its terms; and

- It increases the costs of negotiating and entering into contracts as the terms have to be dealt with separately.

77. Two aspects of contracts that can differ considerably are the force majeure and suspension clauses. Since these fundamentally shape the risks borne by the various parties, variations in these make it particularly difficult to undertake comparisons easily.

6.5 Lack of understanding of electricity price risk

78. The UMR Research survey identified that many electricity industry participants have a limited understanding of the benefits of hedging and limited knowledge and experience of thinking in terms of managing the risks of electricity prices moving. Many respondents essentially saw those responsible for the purchase of electricity in an organisation as engaged primarily in a procurement role and not in a risk management role.

79. Some parties clearly perceive electricity price risks, especially those arising from dry-years, as requiring political interference in the market rather than commercial actions undertaken by them. This may be partly due to a lack of understanding about price risk management techniques; although it could also reflect a judgement that political interference is likely to be beneficial to the party itself compared with the alternatives. Others that call for political involvement are motivated by what they perceive to be issues arising from the exercise of market power by some participants.

6.6 Limits on issues to be addressed by package

80. There were also a number of other issues the Group identified from considering the survey and the other information it gathered which it decided lay outside its mandate to consider or make recommendations to the Commission upon. These were:

- The adequacy or otherwise of the level of competition in the various electricity markets – retail, wholesale, system operation, reserves, frequency keeping, etc. The Group noted that this was being actively considered by the Commerce Commission and it duplicating its work was undesirable;

- The structures of the wholesale and retail markets;

- The legal separation of the ownership of retailers and generators;

- Issues underlying the spot wholesale electricity market;

- The sufficiency of the level of generation for security of supply;

- The ownership of market participants; and
- The overall regulatory arrangements of the electricity industry.

7 EVALUATION CRITERIA

81. The Group assessed each of the initiatives it considered in terms of whether it would contribute towards addressing the electricity price risk management problems it had identified in Section 6 above.

82. The Group also considered the likely economic costs and benefits that would flow from each initiative. It did not conduct a formal quantitative assessment of these but did assess them qualitatively and tried to gauge the likely net benefits (or costs) of each.

83. The other factor which the Group considered was the likely time it would take to implement each initiative. It considered that, other things being equal, it would prefer the initiative which would take the shorter time to implement.

8 ANALYSIS OF PROPOSED INITIATIVES

8.1 The preferred package of initiatives

84. The Group's preferred package of initiatives is:

- The compulsory web-based publication of the key terms and conditions of all contracts entered into by parties that consume above a minimum level of electricity per year;
- The Commission inviting the current owners of the web-based electricity contracts trading platform, EnergyHedge, to further develop its services;
- Development of a mechanism to hedge AC transmission costs by changing the allocation of loss and constraint rentals;
- Support from the Commission for the development jointly by consumers and retailers of a model master agreement for the purchase and sale of financial contracts relating to electricity;
- Centralised web-based publication of planned outage and fuel stock information by the Commission;
- The Commission promoting greater purchaser understanding of electricity price risk management; and
- A regular survey of electricity market participants to ensure improvements in hedging are on track.

8.2 Evaluation of the preferred package

8.2.1 Publication of the key terms and conditions of all contracts

85. The proposed initiative is the compulsory web-based publication of the key terms and conditions of all contracts (i.e. CfD, FPW and variants) relating to electricity traded by those that consume above a specified quantity of electricity in a year. The minimum quantity would be set so as to capture all the relevant information necessary to identify accurately the forward price curve without imposing unnecessary costs on consumers of relatively small quantities. The current suggestion is 10 GWh per year but research would be needed to confirm this figure as appropriate. The details to be published would be the date of the agreement, contracted quantities, prices, region, start and end dates and whether the agreement includes clauses providing for: price escalation; suspension in the event of a force majeure; suspension by the seller of the delivery obligation on other grounds; the treatment of any carbon tax charge; and the treatment of levies and taxes in calculating charges. The following suggests how contract details might be presented.

Standardised Contract								Do you have any of the following provisions?						
Trade Date	Volume	Region	Start	End	Price	FPVV/CfD	Profile	Applicable	S1	S2	S3	S4	S5	S6
Q4 2005	5 MW	Waikato / BOP	Q1 2006	Q3 2009	$73.45	CfD	BL	Yes	No	No	No	No	No	No
Q4 2005	1 MW	Southland / Otago	Q1 2006	Q4 2006	$69.50	CfD	Profile	No	N/A	N/A	N/A	N/A	N/A	N/A
Q4 2005	0.5 MW	Auckland / North	Q1 2007	Q3 2009	$72.50	CfD	BL	Yes	No	Yes	Yes	Yes	No	No
Q4 2005	10 MW	Waikato / BOP	Q4 2005	Q4 2008	$75.00	CfD	Profile	No	N/A	N/A	N/A	N/A	N/A	N/A
Q4 2005	-	Hawkes Bay / East Cape	Q1 2006	Q3 2009	$73.45	FPVV	-	Yes	No	Yes	Yes	No	No	No
Q4 2005	1 MW	Wellington / Kapiti	Q1 2006	Q4 2006	$69.50	CfD	BL	Yes	No	No	No	No	No	No
Q4 2005	-	Taranaki / Manawatu	Q1 2007	Q3 2009	$72.50	FPVV	-	Yes	No	No	No	No	No	No
Q4 2005	10 MW	Nelson / Westland	Q4 2005	Q4 2008	$75.00	CfD	BL	Yes	No	No	No	No	No	No
Q4 2005	5 MW	Canterbury	Q1 2006	Q3 2009	$73.45	CfD	BL	Yes	No	Yes	Yes	No	No	No
Q4 2005	1 MW	Southland / Otago	Q1 2006	Q4 2006	$69.50	CfD	BL	Yes	No	No	No	No	No	No
Q4 2005	-	Auckland / North	Q1 2007	Q3 2009	$72.50	FPVV	-	Yes	No	No	No	No	No	No
Q4 2005	10 MW	Waikato / BOP	Q4 2005	Q4 2008	$75.00	CfD	BL	Yes	No	No	No	No	No	Yes

Standardised Contract
Schedule 1: Escalation
Schedule 2: Force Majeure
Schedule 3: Suspension
Schedule 4: Carbon Tax
Schedule 5: Levies / Tax Pass Through
Schedule 6: Other Terms and Conditions

86. The identities of the counterparties would not be published. The seller of a contract would be required to post the details on a website specified by the Commission. The Commission would notify the purchaser and give them the opportunity to dispute the accuracy of the details. Details of undisputed contracts would be published on the webpage for everyone to see.

Benefits

87. The potential benefits from the initiative arise through the direct effects of increasing information about risk management market activity on market behaviour, and the indirect effects from how this information affects perceptions about market power, or the exercise of market power, if it exists.

88. The following are the benefits from the direct effect of increasing the availability of information by publication of contract details:

- Parties with price risk exposure will have ready access to timely information for comparing prices;

- Greater transparency is likely to set in train the development and use of more standardised contracts;

- Greater transparency is likely to lead to the development and spread of more innovative risk management arrangements and to the provision of new services related to analysing and reporting the information; and

- The costs currently incurred publishing the fixed price contract index will be avoided.

89. The nature of the indirect benefits will partly depend on whether the perception of some parties that market power is being exercised by retailer-generators is correct or not. If the perception is not well-founded, publication is likely to help dispel the false notions. If the perception is well-founded, publication is likely to help expose the use of market power and so aid in it being checked by regulators. Either way, there will be an indirect benefit from publication.

Costs and risks

90. The initiative would impose some modest one-off costs associated with developing the rules and web-based platform. It would also impose some on-going compliance costs for maintaining the rules and operating the webpage and for meeting the requirement on sellers to provide the information for the webpage and buyers to check it.

91. It is unlikely that publication of contract details would effectively increase the risks of collusion by allowing parties to observe the actual pricing behaviour of competitors and so make detection of breaches of collusive agreements easier. This is because the identities of the counterparties will not be known; and so it will not make enforcing collusive agreements easier. On the contrary, the higher level of exposure is likely to make it easier for the regulator to detect collusive behaviour.

92. Enforcement of the requirement to publish accurate details may be difficult in some circumstances if the counterparties agree to withhold or falsify information. But the Commission will know in aggregate the levels of sales disclosed by various generators and retailers, and also grossly false contractual information is likely to stand out. So the targets to investigate for incomplete or incorrect returns should be relatively easy to identify.

Timeframe

93. The rules to implement this initiative would probably take 6months to prepare and another 3 months to consult upon and provide recommendations to the Minister. The development of the website infrastructure is likely to take about 6 months. This initiative could be implemented within a 1 year timeframe.

Assessment

94. This initiative is low cost, requiring minimal IT and rules development expenditure and minimal ongoing administration and compliance costs. The

main risk is in regard to facilitating collusive behaviour, and this appears to be negligible as the competition regulator will also have more information with which to monitor participant behaviour. It appears highly likely the initiative will produce significant net market benefits.

8.2.2 Development of EnergyHedge

95. This initiative involves the Commission inviting the current owners of the web-based electricity contracts trading platform, *EnergyHedge*, to develop its services.

96. One possible development is to add a facility to show for contracts traded what the 'equivalent' price would have been at other node. This would facilitate comparing OTC contracts at other nodes with prices being traded on *EnergyHedge*. Other possible developments are to extend the term of contracts covered from two years to three years, to encourage more participants to offer and bid on behalf of non-participants, and to stand ready to make prices to non-participants based on the offers and bids in the market.

97. The development of an automatic spread trade facility would also allow participants to bring together the trading interests for contracts of different terms. Offers and bids made with this facility would only be valid and shown if there was a bid or offer for a contract relating to another month or quarter at a spread in prices smaller or greater than some figure preset by the trader. If one leg of the order is 'taken', then the other leg of the spread is automatically traded. Unless both legs for the spread trader can be dealt simultaneously then no trade occurs.

98. The development of a strip trading facility is a further possibility. This would allow an order to be placed simultaneously to trade contracts for a series of contiguous quarters when the prices for the individual contracts are such as to yield an average price for the whole period covered that is acceptable to the bidder or offeror. This allows placing orders for quarters covering one or two years, for example, and having trades executed irrespective of the prices in each quarter provided the price for the whole period is acceptable.

99. Spread trading is a well established method by which dealers improve liquidity for hedging arrangements by drawing on demand and supply for contracts for other terms. Strip trading is a more recent development, but has been used with considerable success in promoting hedging volume in the Australian electricity market. The advent of computerised trading platforms vastly improves the ability to use spread trading to generate liquidity and has made strip trading feasible.

Benefits

100. If *EnergyHedge* was further developed by these initiatives into an active market for term contracts for electricity which non-participants could readily access indirectly then all the benefits of having an effective mechanism for hedging identified above would be achieved. That direct involvement is

restricted to parties with a credit standing acceptable to all the other participants does not undermine this.

101. The rules of *EnergyHedge* are very similar to those of the foreign exchange market which operates in almost every country in the world. The limitation on the parties that can be direct participants has developed because of the significant settlement risks faced by the participants in the foreign exchange market. The obligations around making two-way prices have developed to enhance liquidity. This stems from the desire of banks to have some certainty about their ability to trade out of positions when making prices for their own customers.

102. No one would suggest that these arrangements in the foreign exchange market have not provided economies with efficient and effective access to hedges for foreign exchange risks. So, in principal, there is no reason to believe the same arrangements would not provide effective hedging opportunities in the New Zealand electricity market.

Costs and risks

103. One suggested cost is that the initiative could stifle the development of alternative trading facilities because *EnergyHedge* will be seen as the preferred vehicle. This concern is unrealistic; without retailer-generator backing, another trading vehicle will not be successful and retailer-generators are unlikely to voluntarily abandon *EnergyHedge* in favour of an alternative, unless it was likely to offer superior risk management characteristics.

104. The implementation and monitoring requirements of the initiative for the Commission are low. The current owners of *EnergyHedge* are unlikely to pursue further development unless they judge the benefit to them will outweigh the costs.

105. There is currently suspicion in some quarters that *EnergyHedge* might help retailer-generators to communicate their respective views of ‘satisfactory’ prices to one another and hence facilitate collusion between them. Collusion also requires the ability to punish those that breach ‘understandings’. There is no obvious way retailer-generators can achieve this.

106. There is also the possibility that the further development of *EnergyHedge* could entrench its owners in a stronger position to resist future regulatory interventions to develop the market for term contracts. The significant regulatory powers available to the Commission suggest this is unlikely.

107. Finally, given that implementation of the developments will be in the hands of the owners of *EnergyHedge* there is a risk that they will not deliver. There is also a risk that the developments will not be successful.

Timeframe

108. No formal rule development is required for this initiative and delivery is expected to be 6-12 months.

Assessment

109. At worst, the initiative would result in very little change to *EnergyHedge* trading volumes and participation and any development costs incurred by the owners would be wasted. At best, the initiative could result in a very significant improvement in the capacity to trade and hedge electricity and to a virtuous cycle of increased trading volumes improving liquidity that, in turn, attracts even more trading volumes. The initiative could potentially overcome in large measure the criticisms relating to the ability to manage electricity price risks. If successful, the initiative might provide a forward price curve out to three years. This would be of considerable benefit to both participants and non-participants in *EnergyHedge*. The net market benefit of success with the initiative would be very material.

8.2.3 Development of a mechanism to hedge AC transmission costs

110. This initiative involves the development of a mechanism to hedge AC transmission costs by changing the allocation of loss and constraint rentals. Under the arrangement the rentals will go monthly to the purchasers of electricity from the clearing manager at nodes with prices above a reference price. Allocation to these purchasers will be pro-rata with the volume weighted nodal price differential they actually faced.

111. In essence, the rentals will be allocated monthly to wholesale market purchasers in proportion to their locational price risk. The largest value of rentals would be allocated to purchasers facing the highest nodal price differences above the reference price on the basis of the relative quantity of energy they purchased at those prices.

112. This approach, dubbed locational rental allocation (LRA), is new and has not been implemented elsewhere. It will require further development before implementation. A fuller description of LRAs and the mathematics behind it is contained in the *Technical Paper*.

113. The key policy choices regarding the methodology are:

- The choice of reference price. The higher the price the more concentrated the allocation of rentals, the lower the price the more thinly spread they are;

- Whether net or gross load should be used to determine the allocations to different parties. This affects the allocation to parties with generation. The gross approach is favoured because this means there is no discrimination between the self-supply of hedge cover through provision of generation and purchase of hedges from other parties; and

- Whether the load used to determine allocation should be lagged or fixed in some way to minimise the adverse effects of allocating rentals on the basis of relative nodal prices on the efficiency of the nodal price signals. If rental allocation is based on current consumption then this mutes the effect of high nodal prices on consumption, although it also improves the effectiveness of the allocations to offset locational price risks. This is discussed more fully in the Technical Paper.

114. The DC loss and constraint rentals would continue to be allocated to the parties paying for the link; the South Island generators.

Benefits

More efficient management of locational price risk

115. Allocating HVAC rentals to the participants that effectively paid them is a very direct method of allowing them to manage a significant component of their locational price risk. Only the locational price risk related to the imported component of electricity in a region will be covered by LRAs.

More depth and liquidity in the market for electricity contracts

116. If parties in the market for electricity contracts can rely on rental allocations to cover their locational price risk they may be more willing to concentrate their energy contracts around a limited range of nodes. This would increase liquidity in the market for these contracts and, in so doing, increase its efficiency.

Reduced barriers to entry in the retail market

117. The LRA initiative could significantly reduce barriers to entry for new retailers seeking to enter retail markets in constrained regions of the grid distant from where they own generation. The new retailers might be wholly independent or vertically integrated retailers with generation located outside the constrained region.

118. The ability of LRAs to do this will depend on how effectively they offset the actual price risks faced by retailers, and this is currently not certain because of the lack of practical experience with their use and decisions about matters like the reference price still have to be made.

More efficient consumption and investment decisions by consumers

119. The LRA initiative reduces the efficiency of the wholesale price signals for price-taking consumers, and probably also for other small consumers. On the other hand, compared with the situation of no transmission price risk hedges, the LRA initiative improves the price signals for large non-price taking consumers.

120. In the short-run, these efficiency effects are likely to be limited because the demand for electricity is highly inelastic. In the long-run, the more efficient price signals for larger consumers which are able to influence the price they pay by varying their own demand will improve the investment decisions of this group because they will be less prone to inefficient investment in co-generation, relocation to unconstrained areas of the grid and to delay investments that increase load.

Lower complexity to operate and understand

121. Compared with other alternatives, such as FTRs, LRAs are likely to be less complex to operate and for market participants to understand and hence manage.

Reduced generator gaming incentives

122. When there are no transmission hedges, retailer-generators with a net generation position in a constrained region may have an incentive to adopt offering strategies that cause grid constraints to bind and prices to rise at the local node. Converse incentives may arise for retailer-generators with a net retail position. The LRA initiative reduces these incentives as the rental allocations partly offset the price movements. It does not, however, eliminate all the opportunities for generators to game.

Flexibility to adopt other approaches to managing locational price risk

123. The LRA initiative leaves it to the rental recipients to decide how they wish to contract for hedge cover for their locational price risks. This means that innovation in transmission risk management is encouraged. For example, if there was industry interest in introducing FTRs for the core grid, this could be accommodated even though LRAs are issued.

Reduced lobbying and litigation activity

124. The LRA initiative greatly reduces the disparity between the commercial and economic benefits of transmission investment. This should reduce consumer and retailer-generator groups incentives to lobby for (or against) transmission investment purely for the wealth transfers that would accrue to them. It should also greatly reduce the incentives for parties to litigate such decisions.

Costs and risks

125. We have already noted that the LRA initiative reduces the efficiency of the wholesale price signals for price-taking consumers and probably also for other small consumers. On the other hand, compared with the situation of no transmission price risk hedges, the LRA initiative improves the price signals for large consumers who are able to influence the price they pay by varying their demand. Although price-taking consumers are far more numerous than those that can influence their own price, the vast majority of price-takers are on fixed price retail tariffs and so are not exposed to wholesale prices. On balance, the LRA initiative has less of an effect on efficiency through reducing the efficiency of the decisions of price-takers than through improving the efficiency of decisions of those able to influence their own price by varying their demand.

126. It is difficult to determine at this stage of the development of the LRA concept the extent of any inaccuracies in the allocation of rentals.

127. The implementation of the LRA initiative will require the current allocation of loss and constraint rentals to cease. Undoubtedly in the move from the current arrangements to the LRA there will be some parties that ‘win’ and some that

‘lose’. Managing the transition through these wealth transfers will present political challenges.

128. The costs of implementing the LRA initiative will comprise the work required to create and agree the new methodology, and the information technology development costs associated with changing the model used to determine dispatch and rentals and reconfiguring the clearing manager’s systems. The current indications are, however, that most of the decisions required to implement LRAs about things like reference points should be reasonably straightforward.

129. The ongoing operation and administration of the LRA regime should also be reasonably straightforward if the allocation task is integrated with the clearing and settlement systems operated by the clearing manager. The current costs incurred by Transpower and distribution companies in allocating rentals will no longer be incurred.

Timeframe

130. The highly technical nature of the allocation methodology will require development of a suite of complex rules. This will probably require two rounds of consultation. The IT elements of the LRA regime could be developed and tested in parallel with the completion of this activity. The overall timeframe for implementation is in the order of 18 months – 24 months.

Assessment

131. The LRA initiative would facilitate more efficient management of transmission related and electricity price risks. The LRAs should also improve the efficiency of decision-making by large non-price taking consumers and reduce incentives for them to unproductively lobby for, or against, transmission investment proposals. There may also be benefits in regard to reducing barriers to entry to the retail market and reducing incentives on retailer-generators to use local market power to manipulate local prices.

132. The primary cost of the LRA initiative is likely to be in finalising the development of the concept and testing it and undertaking the IT development to implement the regime. There may be some costs from distorting wholesale market prices faced by price-taking consumers; many of them do not face wholesale prices anyway.

133. Overall, the economic benefits from this initiative appear far greater than the costs of implementation and operation, a large and positive net market benefit appears likely.

134. The Group considers that an effective mechanism for participants to manage locational based risks is needed without further delay. It is clear after more than 10 years of industry debate there is no ‘perfect’ solution.

135. The LRA proposal is new and requires more detailed testing. However, the Group’s consensus view is that, on balance, the LRA mechanism offers the

possibility of a positive way forward which should be progressed with urgency. In the Group's view the industry needs to come together and make it happen.

8.2.4 Support for a model master agreement

136. A model master agreement for the purchase and sale of electricity contracts is currently being developed by the five major retailer-generators and the Major Electricity Users Group (MEUG) and Business New Zealand. This activity grew out of discussions held by the Group. The model master agreement being developed, like the customised agreements currently in use, is based on the International Swaps and Derivatives Association (ISDA) model agreement. The initiative is that the Commission lends its support for the development and adoption of this model master agreement.

Benefits

137. The principal benefits of having a model master agreement are to:

- Lower transaction costs for all parties by sharply reducing the frequency at which it is necessary to scrutinise and renegotiate agreements;
- Make it easier to compare prices between contracts because the aspects on which they vary will be reduced due to greater standardisation of terms on the model agreement;
- Increase the use of contracts by lowering the transaction costs of using them; and
- Increase the ease of finding other contracts which are fungible with an existing one and so facilitate offsetting or modify existing price risk positions.

The Commission lending its support the effort to develop and implement such a model agreement will help realise these benefits.

Costs and risks

138. The costs of developing the model master agreement are not attributable to the initiative as the initiative assumes a model agreement will be developed by the private sector partners anyway.

139. The costs associated with the initiative are those incurred by the Commission evaluating whether the outcome of the private activity is an appropriate model for it to lend its support to and encourage parties to adopt. This will essentially involve the Commission assessing whether and in what regards the model master agreement satisfies the statutory obligations of the Commission in terms of its principal objectives, and the specific outcomes it is required to seek.

140. The Commission will also incur small costs in monitoring adoption rates. This activity could be combined with the requirement to publish contract details and the annual survey.

Timeframe

141. Development of the model master agreement within the industry is already progressing well. It is estimated that the model will be finalised within six months. The minimal requirements on the Commission means the initiative of providing the model support could be implemented within three months of the model master agreement being finalised.

Assessment

142. The initiative is likely to produce net market benefits by achieving more widespread use of the model master agreement and more rapid adoption.

8.2.5 Centralised publication of outage and fuel information

143. This initiative involves the Commission centralising planned outage and fuel stock information onto a readily accessible web platform. The information would be presented in GWh equivalents so it is meaningful for risk management purposes.

144. The information to be published would include:

- Current and historic hydro storage levels and inflows;
- Current and historic wholesale coal, gas and oil prices from both spot and forward prices, when readily obtainable;
- Planned generation, transmission and large load outages and the effect on expected supply capability over the period of the outage, by region as applicable; and
- Medium and long-term gas and coal availability at key locations, like Huntly, when readily obtainable.

145. An independent agency would be contracted to collate and publish the information. The contracted agency would be required to survey market participants for their views on accessibility of the website and the format of the data. The contracted agency would also be required to provide performance reports on the volume of website hits, percentage of uptime and percentage of help-desk inquiries resolved within defined time periods.

Benefits

146. The potential benefit is that it may improve end-users' electricity purchasing and risk management decisions through assisting them forming more accurate views about likely future electricity prices.

Costs and risks

147. Implementing the initiative should be straight-forward. Some IT development expenditure would be required to establish the web-page and to create performance reporting and survey templates.

148. If information disclosure rules are required to be imposed on Transpower and generators, further one-off costs will be incurred to develop and consult on these rules. There would be further costs refining the rules over time as experience is gained with using them.

149. The initiative would incur regular on-going costs arising from the appointment of the independent service provider to collate and report the planned outage and fuel information and to undertake IT maintenance, the survey of performance, and operate the help desk.

150. The initiative would require Transpower and generators to provide information to a higher standard of care than the ‘reasonable endeavours’ which is currently the requirement. This is likely to impose higher costs. The initiative also envisages large consumers providing planned outage information which they do not currently do. This would impose additional compliance costs upon this group.

151. There would also be modest ongoing costs for the time the Commission spends managing the service provider contract and responding to alleged breaches of the information disclosure requirements.

152. The initiative may result in Transpower and generator participants adopting a more conservative approach to outage schedule publication so that it only publishes when there is a high probability the outage occurs. On the other hand, market participants will be able to rely upon the information more than under current arrangements.

Timeframe

153. If the Commission decided to adopt this initiative it would need to formulate rules specifying how and when information would be disclosed. Some of this information is likely to be held to be commercially sensitive and so the precise form of the rules will be contentious. The rules would probably take 6 – 12 months to prepare and another 3 months to consult on and provide recommendations to the Minister. The development of the appropriate technical infrastructure would take approximately six months. The initiative could therefore be implemented within a 9 – 15 month timeframe.

Assessment

154. The benefits of the initiative arise primarily from end-users adopting more efficient risk management practices. The costs of the initiative relate primarily to IT development, administration, and compliance. Overall, the initiative appears likely to produce small-moderate net market benefits.

8.2.6 Promoting greater understanding of price risks

155. This initiative involves the Commission promoting greater purchaser understanding of the extent and nature of electricity price risks and techniques for price risk management. This is to be achieved by encouraging the development and provision by independent parties of information programmes about the techniques and products available, and by publishing the availability of risk management training courses. In addition, the Commission would request private organisations to facilitate the certification of training providers and risk advisors.

Benefits

156. Increased training of purchasers and greater use of risk advisors is likely to support more widespread participation in risk management activities.

157. The greater use of risk advisors in response to the initiative may encourage advisors to provide new services. The use of risk advisors may encourage clients to pursue a wider range of risk management options with resulting gains in efficiency and effectiveness.

158. Without this greater awareness and 'ownership' of price risk by participants, demand for risk management services is unlikely to develop, and the market for hedging will not grow. Suboptimal arrangements will only become entrenched, including calls for political intervention to address hydro shortages, or to rescue parties with poor hedging strategies.

Costs and risks

159. The Commission would incur costs of developing and providing the information material and updating it as required.

160. The Commission and other organisations will also incur one-off costs of developing certification standards, and on-going costs of assessing new membership applications. Training providers and risk advisors will incur ongoing costs of complying with the certification standards.

161. As the certification status of providers and advisors would be clearly identified in the pamphlet, the initiative would provide strong incentives for them to obtain certification for their activities. Most training providers and risk advisors would incur certification costs.

162. There is a risk that the certification requirement may increase barriers to entry in the markets for training and risk advice.

Timeframe

163. As no formal rule development is required for this initiative, the initiative is expected to take approximately 6-12 months to implement.

Assessment

164. The benefits of the initiative are uncertain as there is some uncertainty as to how effective the Commission will be in persuading firms to invest more in risk management education and skill development. The initiative involves very low establishment costs, and can be easily discontinued if it proves ineffective at stimulating greater interest in risk management. On balance, the initiative is likely to produce positive net market benefits.

8.2.7 A regular survey of electricity market participants

165. The initiative is conducting a regular survey of electricity market participants to identify the extent to which various methods of price risk management are used and the views of participants on how efficiently and effectively price risks are able to be managed. The survey to be funded and overseen by the Commission but conducted by a specialist firm. Only aggregate and tabulated results would be published. The survey would initially be conducted annually, but later it may be held less frequently.

166. The survey would be voluntary for participants and cover all participants in the wholesale electricity market and a selection of large, medium, and small end-users that contract for supply from users of the wholesale market.

167. The questions in the annual survey would be similar to those in the 2005 survey that informed the work of the Group. The intention would be to track changes over time in market practices and the perceptions of market participants and others of the ease of managing transmission related and price risks. To this end the survey would cover both practices and perceptions.

Benefits

168. The primary benefit of the initiative is that it should provide the Commission and other government officials with more timely and more useful information to determine the effect current policy is having towards achieving objectives and what, if any, further policy initiatives are desirable. Better policy decisions in this area have the potential to create large efficiency gains for the economy as electricity is such an essential component of its operations.

169. The annual survey is also likely to generate greater knowledge and awareness of price risk management and the opportunities it provides.

Costs and risks

170. Implementing the initiative is relatively straight-forward as it involves largely repeating the 2005 survey. There will be the direct costs on respondents and the Commission would incur annual costs to manage the survey firm and pay for it to conduct the surveys.

171. There is some potential for respondents to ‘collude’ in their responses in order to shape policy in a direction in which they would like it to develop.

172. There is also some potential that participants will try to window-dress their behaviour or use of derivatives in the lead up to the survey. This type of behaviour is endemic in surveys to measure radio and TV audience ratings.

173. There is also a risk the annual survey will attract decreasing response rates as time goes by, but it will always be open to the Commission to discontinue conducting the survey and, given its aim is to track if policy is working, it is to be hoped the reason for conducting it disappear sooner rather than latter because the policy has achieved all that is practicable.

Timeframe

174. The inaugural survey has already been completed and a follow-up survey would only require a refinement of the survey questions. A second survey could be started within two months.

Assessment

175. An annual survey has the potential to result in more informed policy making and greater awareness of risk management, which, over time, should produce a better opportunities for risk management and reduced regulatory risks. Given the current paucity of solid information, the benefits are highly likely to exceed the costs.

8.3 Contribution to resolving key problems

176. The key problems for electricity risk managers as identified by the Group are discussed in Section 6 . The table summarises the direct and indirect contribution towards resolving each of these problems of each initiative in the Group's preferred package. Three ticks indicate the initiative makes a large contribution to resolving the problem corresponding to the column. Two ticks indicate a moderate contribution and one tick a minor contribution.

	Lack of robust information	Lack of confidence in competitiveness of market	Lack of suitable instruments to manage transmission price risks	High participation and transaction costs	Lack of understanding of risk manage-ment
Publication of contract details	✓✓✓	✓✓		✓✓	✓
Development of *EnergyHedge*	✓✓	✓✓✓		✓✓✓	
Locational Rental Allocation (LRA)	✓	✓✓	✓✓	✓✓	
Support for developing a model master agreement	✓	✓		✓✓	

	Lack of robust information	Lack of confidence in competitiveness of market	Lack of suitable instruments to manage transmission price risks	High participation and transaction costs	Lack of understanding of risk manage-ment
Publication of outage and fuel data	✓	✓		✓	✓
Promotion of training & advisors	✓	✓			✓
Annual survey of market participants	✓✓	✓			✓
Does the package address key problems?	Yes	Yes but even better if obtain good Energy-Hedge Outcomes	Yes	Yes if good Energy-Hedge outcomes obtained	A start. Will build as experience gained

177. It can be seen from the table that the package addresses the key problems the Group identified. With the exception of the lack of suitable instruments to deal with transmission related price risks, several of the initiatives contribute to dealing with each problem. Moreover, each initiative contributes towards resolving more than one of the key problems. The package is highly linked and integrated.

178. The membership of the Group was drawn from a wide range of backgrounds and interests. Through the very open and frank debates it held a strong level of agreement on the general approach and the proposed approach was reached. In the view of the Group, the package:

- Represents a broad-based approach which should resolve relatively quickly all the risk management issues that it has identified;
- Is such that, the sum of the parts will be much more effective than the individual initiatives on their own;
- Creates incentives and opportunities that will lead electricity market participants to adopt more effective risk management practices;
- Creates a dynamic of better practices by some facilitating and encouraging more widespread adoption of better practices;
- Encourages the development of further risk management opportunities by market players;
- Does not require the establishment and maintenance of a costly market to try to provided high levels of liquidity when trading volumes are likely

to be modest and demand for risk management services is still uncertain;

- Does not require heavy regulatory intervention or high establishment costs and hence does not incur the risks of unintended consequences and heavy waste of resources; and

- Does not preclude recourse to other measures in the future. In any event, the package recommended by the Group would be helpful to any future scenario.

The Group is of the view that the Commission and the industry should proceed to put this package in place without delay, subject to satisfactorily developing and testing a working model of the LRA proposal.

8.4 Initiatives not preferred by the Group

179. In addition to the above initiatives it has recommended to the Commission, the Group analysed at some length several other initiatives. These have been raised in industry debates on price risk management or were identified as potential measures for the Commission to consider in the GPS issued in October 2004.

180. After detailed consideration, the Group put these other initiatives into one of two categories: 'wait and see if needed', or 'do not use'.

181. In the 'wait and see if needed' basket are:

- A requirement for market participants to use a standardised contract-for-differences (CfD) contract to trade base-load electricity. The contracts would relate to one of three locations – Benmore, Haywards and Otahuhu – and there would be maturities out to, say, five years. Participants would be free to trade the standardised CfDs through the market of their choice or bi-laterally, and they would be free to trade contracts of other types for non-base-load electricity;

- A requirement for market participants to trade mandatory standardised CfD on a designated exchange; and

- A requirement that organisations which are both generators and retailers should 'synthetically' separate these activities. They would be required to have separate trading teams for the two components of the business and to obtain any forward contracts to manage price risks through a blind market and in competition with other potential purchasers or sellers of the contracts. They would be prohibited from sharing between the two teams information that could affect prices internally without prior public disclosure.

182. In the 'do not use' basket are:

- A requirement that generators publicly offer a minimum volume of forward contracts covering spot price risks over the coming year, at least. The required volume to be offered by each generator would be set as a percentage of its forecast net generation level with rules allowing adjustments to be made by the Commission if the forecasts proved materially inaccurate. The initiative requires the net generator make public offers and this does not necessarily require it to entry into actual contracts with purchasers; and

- A requirement that wholesale market purchasers maintain a minimum level of forward contract cover for the year ahead that insulates them from spot price movements. This initiative requires purchasers to actually enter into contracts to manage price risk rather than just make public bids to do so.

183. The Group's evaluation of these non-preferred initiatives is set out in detail in the accompanying *Technical Paper*. In summary, the Group found that they would involve significant costs and material risks without sufficient and likely off-setting benefits. These non-preferred options are therefore not recommended.

184. If it turns out that, after a reasonable period, the Group's preferred package does not adequately address the problems in section 5 above, further work should be undertaken to see if it is possible to reduce the costs and risks of the 'wait and see' options before proceeding.

8.5 Financial transmission rights

185. The Group also debated in considerable detail the introduction of financial transmission rights (FTRs) in New Zealand to provide a means for purchasers and sellers to manage locational-based price risks arising from transmission constraints. We have already explained why the nodal characteristic of the New Zealand electricity system gives rise to significant price risks. This risk is also referred to as transmission price risk.

186. The specific proposal the Group evaluated involved the pre-allocation of some FTRs to wholesale market purchasers in some specified regions when two conditions are met. The two conditions were that the nodal prices in the region can be materially affected by transmission capacity constraints, and the level of competition among electricity suppliers in the region is deemed to be inadequate against some criteria. Under the specific proposal the remainder of the FTRs were to be auctioned. The proposal permitted subsequent trading of FTRs among market participants.

187. The majority of the Group decided against recommending to the Commission the introduction of FTRs. This was because it judged that the additional costs and complications for understanding and managing FTRs compared with LRAs more than outweighed the benefit from FTRs because they generally convey more efficient price signals than LRAs. Uncertainties around how to identify the regions in which FTRs should be pre-allocated because of lack of competition also counted against FTRs with the Group. Concern that the

complexity of FTRs may preclude many from utilising them and so limit their effectiveness as a solution in practice was a further factor considered by the Group. The decision was to recommend LRAs as part of the package and to also recommend that the design features of LRAs should be urgently finalised and LRAs be robustly tested to more fully understand the actual outcomes they will produce.[9]

9 NEXT STEPS

188. After preliminary consideration of the Group's recommendations, the Commission's initial view is that the preferred package should be seriously considered for implementation.

189. Before making decisions on this matter, however, the Commission wishes to obtain feedback from interested parties on the proposed initiatives. Once final decisions are made on initiatives requiring rule changes, the Commission will consult on specific proposals in accordance with the requirements of the Electricity Act 1992.

9.1 Relative priorities

190. Based on the analysis completed by the Group, the Commission has categorised the initiatives into priority levels.

[9] For a full discussion and evaluation of FTRs compared with LRAs see Technical paper section 8.

High priority	Medium priority	Lower priority
Publication of contract details Development of EnergyHedge Locational Rental Allocation	Support for model master agreement Annual survey	Publication of outage and fuel data Promotion of training & advisors

9.2 Timeframes for implementation

191. Some of the initiatives are relatively simple to implement but others require a reasonable amount of work to further develop and implement. Initiatives that require rule changes will need to be further specified and consulted on in accordance with the requirements of the Electricity Act 1992. The dates in the following table are based on the assumption that the Commission approves proceeding with each initiative without delay after it has evaluated feedback on this *Overview Paper* and the companion *Technical Paper.*

Initiative	Target date for releasing consultation paper	Target implementation date
Publication of contract details	November 2006	April 2007
Development of *EnergyHedge*	n/a	tbc
Locational Rental Allocation (LRA)	April 2007	July 2008
Support for model master agreement	n/a	November 2006
Publication of outage and fuel data	April 2007	July 2007
Promotion of training & advisors	n/a	October 2006
Annual survey of market participants	n/a	September 2006

9.3 Submissions

192. The Commission invites submissions on both this *Overview Paper* and the accompanying *Technical Paper* including, but not limited to, answers to the specific questions contained in the next subsection of this paper by 5pm on 25 October 2006. .

The Commission's preference is to receive submissions in electronic format (Microsoft Word and/or pdf). The electronic version should be emailed with 'Hedge Market Development – Issues and Options' in the subject header to info@electricitycommission.govt.nz.The Commission will acknowledge receipt of all submissions electronically. Please contact Jenny Walton (Tel: (04) 460 8860 Fax: (04) 460 8879) If you do not receive electronic acknowledgement of your submission within two business days.

193. Your submission is likely to be made available to the general public on the Commission's website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Commission on a confidential basis. All information provided to the Commission is subject to the Official Information Act 1982.

9.4 Discussion questions

194. In addition to any comments you may have on the proposed initiatives the Commission would like responses to the specific questions listed below. The same questions are contained in the *Technical Paper*:

1 The Group defined its policy objective as promoting a well-functioning hedge market. By contrast, the GPS policy objective for the hedge market is to improve transparency and liquidity. The Group questions whether liquidity is a goal in itself, and the extent to which it can be achieved in the New Zealand context. Do submitters agree with the Group's policy objective? If not, please outline what you consider the policy objective should be;

2 Has the Group correctly identified the key problems relating to risk management in Section 6 of this Overview Paper and Section 3.3 of the Technical Paper? If not, please outline what you consider to be the problems;

3 Do you agree that the evaluation criteria outlined in Section 7 of this Overview Paper and Section 4.2 of the Technical Paper are appropriate criteria for assessing the initiatives? If not, please outline the evaluation criteria that you consider more appropriate;

4 Do you consider the Group has correctly identified and described an appropriate range of potential initiatives in Sections 6 and 7 of the Technical Paper? If not, please outline any additional initiatives you believe the Group should have considered;

5 Do you agree with the preferred package described in Section 8 of this Overview Paper and Section 8 of the Technical Paper? If not, please outline the initiatives you consider are more appropriate and describe the benefits they deliver, with particular reference to the policy objectives; and

6 The Group identified two initiatives in the preferred package that, in its view, would make the biggest difference in improving existing market

arrangements: disclosure of contract information and changing the allocation of loss and constraint rentals. Please describe your views on the practicality and acceptability of these initiatives.

10 APPENDICES

10.1 Appendix A: Glossary

Act	The Electricity Act 1992
CfD	Contract-for-differences. An arrangement under which the counter-parties agree to make and receive payments depending on the difference between the current price of electricity and a price specified in the contract
Commission	The Electricity Commission
EnergyHedge	A specific platform for trading electricity contracts for forward delivery dates established by the largest retailer-generators in New Zealand
FTRs	Financial transmission rights, a type of transmission related price hedge
The Group	The Hedge Market Development Steering Group see also HMDSG
GWh	Giga-Watt hours, a unit of measure of electricity
hedge	An arrangement used by businesses and consumers to manage the risks to their incomes or costs that arise because prices vary
HMDSG	Hedge Market Development Steering Group, the ‘Group’.
ISDA	International Swaps and Derivatives Association
location price risk	The risk arising because electricity prices might vary between places
MWh	Mega-Watt hours, a unit of measure of electricity
OTC	A contract acquired over-the-counter or negotiated bi-laterally between the buyer and the seller, in contrast to a standardised exchange traded contract
rentals	Loss and constraint rentals
Rules	The Electricity Governance Rules 2003 and amendments to them
wholesale market	The market for trading physical electricity for ‘immediate’ delivery in New Zealand

10.2 Appendix B: The Hedge Market Development Steering Group

Chairman	Tony Baldwin
Members	Steve Barrett
	Carl Daucher
	Russell Longuet
	Ralph Matthes
	Paul McIver
	James Moulder
	Mark Trigg
Senior Advisor	Tim Street
M-Co Advisor	Carl Hansen
HMDSG Administrators	Trish Bradley
	Darren Gilchrist
	Joe Riley