ELECTRICITY COMMISSION

Hedge Market Development – Issues and Options: Technical Paper

18 July 2006

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1 INTRODUCTION

1.1 Purpose

1. The Government Policy Statement on Electricity Governance of October 2004 (GPS) invites the Electricity Commission to give priority (among other things) to improving hedge market transparency and liquidity.

2. To this end, the Commission created a specific work-stream and formed the Hedge Market Development Steering Group (HMDSG). Its task has been to investigate and consider issues relating to electricity and transmission hedges.

3. The HMDSG has now completed its preliminary consideration of the issues, and assisted the Commission in developing two consultation papers, the purpose of which are to:

   - outline the nature of the current risk management market,
   - identify the key problems with it;
   - describe and evaluate a range of possible options;
   - propose a preferred package; and
   - provide detailed information for interested parties to draw on in making their submissions.

   This Technical Paper traverses the issues and options in some detail. The accompanying Overview Paper summarises the key problems, and the preferred package of initiatives.

1.2 Background

1.2.1 Commission's role

4. The Commission has been established under the Act to provide regulatory oversight of the electricity industry. The Government expects the Commission to put particular emphasis on:

   - security of supply;
   - electricity transmission; and
   - hedge market development[1].

5. The principal objectives of the Commission under the Act are to:

   - ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner; and
   - promote and facilitate the efficient use of electricity.

6. The GPS[2] and Act set out specific outcomes the Commission must seek to achieve. Those with particular relevance to managing electricity price risks include:

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[1] Address from the Minister of Energy on 20 May 2003.

a. energy and other resources are used efficiently;

b. risks (including price risks) relating to security of supply are properly and efficiently managed;

c. barriers to competition in electricity are minimised for the long-term benefit of end-users;

d. incentives for investment in generation, transmission, lines, energy efficiency, and demand-side management are maintained or enhanced and do not discriminate between public and private investment;

e. the full costs of producing and transporting each additional unit of electricity are signalled; and

f. delivered electricity costs and prices are subject to sustained downward pressure.

7. The GPS refers to hedging and hedge markets in a variety of contexts:

a. In relation to security of supply coordination, paragraph 71 of the GPS states that the Commission is expected to be active in monitoring developments, using the powers available to it and, if necessary, make recommendations it believes are necessary to ensure that the market operates efficiently. Paragraph 71 notes that this may involve, among other things, recommending regulations or rules to set requirements on generators to offer, by tender, minimum volumes of contracts, or on retailers and other direct buyers to maintain minimum levels of hedge and contract cover;

b. Paragraph 76 of the GPS states that a transparent and liquid hedge market is a critical component of an efficient wholesale market as it enables market participants to manage their risks and facilitate retail competition. The GPS also notes that concerns are regularly expressed that the current hedge market does not operate particularly well;

c. Paragraph 77 of the GPS points out that the Government has regulation-making powers in relation to hedge markets, in particular requiring disclosure of information, minimum contract offerings, minimum contract purchasing, certain terms and conditions, and posting of prices. However, paragraph 77 notes that the Commission may only recommend regulations if it has first established that there are significant problems that cannot be resolved through voluntary arrangements;

d. Paragraph 78 of the GPS states that the Commission should oversee the development of financial transmission rights (FTRs) to enable market participants to manage risk in respect of transmission losses and constraints. The Government's policy in relation to FTRs is set out in an appendix to the GPS;

e. In relation to retail competition, paragraph 120 of the GPS notes that independent retailers have cited, as a barrier to competition, difficulties in obtaining hedges at reasonable prices from vertically integrated generator/retailers. Paragraph 120 also notes that the Act provides a range of powers relating to hedge markets, and the Commission should exercise these powers, if necessary, to facilitate retail competition; and

f. Paragraph 122 of the GPS states that priority should be given to, among other things, improving hedge market transparency and liquidity.

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[2] A copy of the GPS is available at ww.med.govt.nz/ers/electric/governance-gps/final/index.html

1.2.2 HMDSG Process

8. The HMDSG's first task was to prepare for the Commission an initial a paper on problems and options in relation to the current hedge market. A key problem identified by the Group early on was lack of information on the scope and operation of the hedge market. The HMDSG therefore proposed that the Commission undertake a detailed survey of market participants. The Board agreed and engaged UMR Research (UMR) to conduct the survey.

9. Further details on the survey are set out in Appendix A. UMR's full report with the survey results is available on the Commission's website at:

http://www.electricitycommission.govt.nz/opdev/wholesale/hedgesurvey

10. The HMDSG spent some time considering the nature and extent of perceived problems in relation to the current market. The HMDSG received presentations on these matters from a range of experts.

11. The HMDSG also reviewed the relevant policy objectives. Consistent with the Commission's principal objectives and specific outcomes, the HMDSG considers the policy goal for this project should be a well-functioning market for instruments that buyers and sellers use to manage their spot price risks efficiently.

12. Drawing on the GPS, survey information and various experts, the HMDSG identified a broad range of possible initiatives. These are outlined in Appendices B, C and D.

13. After careful analysis and distillation, the HMDSG identified a package of initiatives that it considers are likely to promote a significantly better functioning market for managing spot price risks. The proposed package is outlined in section 8.3.

14. The HMDSG and the Commission's Board have had several workshops. The Board supports the views of the HMDSG. Before making any firm decisions on the HMDG's recommendations, the Board wishes to discuss the proposals with interested parties.

1.3 Limits of terms of reference

15. There are several issues that, while related to price risk management, were beyond the HMDSG's terms of reference, in particular:

- Adequacy of competition in the physical electricity market;
- Structure of the wholesale and retail market;
- Legal separation of the ownership of retailers and generators;
- Issues underlying the spot wholesale electricity market;
- Sufficiency of generation;
- Ownership of participants; and
- Overall regulatory arrangements for the industry.

16. Initiatives relating primarily to these issues were not developed in any detail as they were outside the terms of reference.

1.4 Submission requirements

17. Proposals have been developed to a stage where consultation with interested parties would be useful. The Commission has identified questions in section 10 that it would like submitters to address in their submissions along with any other issues submitters would like to raise.

18. The Commission invites submissions on this paper by 5pm on 25 October 2006. Please note that submissions received after this date may not be considered.

19. The Commission requests that submissions are provided in electronic format (Microsoft Word). The electronic version should be emailed with 'Hedge Market Development – Issues and Options' in the subject header to info@electricitycommission.govt.nz. Any queries should be directed to:

    Jenny Walton
    Tel: (04) 460 8860

20. The Commission will acknowledge receipt of all submissions electronically. Please contact Jenny Walton if you do not receive electronic acknowledgement of your submission within two business days.

21. 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.

1.5 Terminology

22. Within the hedge market area there is a significant amount of industry jargon. While many of these terms will be common knowledge to industry participants the Commission wanted to clarify the key terms from the outset to ensure a common understanding. The list below contains terms used within this paper and provides a brief definition of the term.

Act	Electricity Act 1992
baseload energy	A flat quantity of electricity
basis risk	The risk that occurs as a result of a mismatch between a particular contract and the underlying risk which the contract is intended to mitigate
BETTA	The electricity market for the United Kingdom (excluding Northern Ireland)
Blind markets	Markets where the participants do not know the identity of the ultimate counter party to the transaction until after the contract is struck
CfD	Contracts for differences
Clearing Manager	The service provider responsible for monitoring prudential security requirements and invoicing and settling electricity and ancillary service payments
COMIT	The market information system for the spot market
Commission	Electricity Commission

commodity market	A market where a product is traded under a standardised contract
counterparty	The other party to a contract
derivative	A financial product with a value derived from an underlying physical product
direct connect customers	Large consumers directly connected to the transmission network
distribution network	A physical system for the conveyance and distribution of Electricity
EnergyHedge	A specific platform used by the five main generator/retailers for trading electricity derivatives in New Zealand
equity market	A market where entities trade company shares, or financial derivatives of these shares (such as options). An equity market is often referred to as a stock market
exchange	A centralised platform used for the trading of specific commodities or derivatives, usually with specific credit requirements
forward price curve	A forward price is the price today at which two parties are willing to settle a transaction at some time in the future. The forward price curve is created from the series of prices for the same product type that commence at the current spot price and continue out into the future
FPVV	Fixed-price variable-volume (a type of electricity contract)
FTRs	Financial Transmission Rights (a type of transmission hedge)
GPS	Government Policy Statement on Electricity Governance (October 2004)
GWAP	Generation-weighted average price
hedge	An instrument used for reducing the risk position of the parties involved[3]
hedge market	The market for the trading of wholesale electricity derivatives
Hybrid FTR	An allocation methodology (first outlined in the Read Report) for loss and constraint rentals that auctions FTRs for the core transmission network but allocates FTRs in areas where retail competition / market power are a concern
HMDSG	Hedge Market Development Steering Group
hub	A reference point that is designed to represent the aggregate of many market nodes
ICPs	Installation control points. A unique identifier for a point of electricity connection for reconciliation purposes
independent generator	Generators that do not own or control any retailing operations
independent retailer	Retailers that do not own or control any generating operations
instantaneous reserve or IR	Generation capacity that is made available to be used in the event of a sudden failure of a generating or transmission facility in order to maintain system frequency at 50 Hz

[3] Technically the word “hedge” is a verb, and is an action that a party takes, such as in the term “hedge your bets”. However, the common usage in New Zealand is to refer to a “hedge” as a product used for managing risk.

ISDA	International Swaps and Derivatives Association
liquidity	A term often used to describe the effectiveness of financial markets. A liquid market exists when a contract holder can readily liquidate their holdings without depressing market prices and without incurring large transaction costs
load	The consumption of electricity
local generator	A generator located close to the node under consideration
local retailer	A retailer located close to the node under consideration
locational price risk	The risk faced by participants as a result of having generation (or risk management contracts) located at a distance from the location of load
LRA	Locational Rental Allocation (a methodology for rebating loss and constraint rentals)
LWAP	Load-weighted average price
MARIA	Metering and Reconciliation Information Agreement
market depth	The volume of contracts available for trade at any point in time
MED	Ministry of Economic Development
MEUG	Major Electricity Users Group
Minister	Minister of Energy
national grid	The New Zealand electricity transmission system
NEM	National Electricity Market, the electricity market for Queensland, New South Wales, Australian Capital Territory, South Australia and Tasmania
NERA Report	A report on "Hedge Markets and Vertical Integration in the New Zealand Electricity Sector" prepared by NERA Consulting for Contact Energy in October 2004
NGOs	Non-government organisations
nodal pricing	The methodology used for pricing electricity in the wholesale spot market. This is also sometimes referred to as locational marginal pricing or LMP
Noordpool	The electricity market for the Nordic countries of Norway, Sweden, Denmark and Finland
NZEM	The New Zealand Electricity Market, which operated the New Zealand wholesale electricity spot market from 1 October 1996 until 29 February 2004
OTC	Over-the-counter - The term used for bilateral negotiation of the supply of goods and services
physical electricity market	The market for the physical supply and use of electricity
PJM	The Pennsylvania, New Jersey and Maryland electricity market, which is the main electricity market for the North-eastern United States
PPAs	Power Purchase Agreements
price-taking consumers	Consumers who are unable to influence market prices by changing load
primary node	The node at which generation or load is located
Read Report	The report on FTRs prepared by EGR Consulting Limited for the MED dated 8 May 2002
Regulations	Electricity Governance Regulations 2003

Rentals	Loss and constraint rentals generated by locational marginal pricing
reserves market	A market for the supply of instantaneous reserves to the system operator
RFP	Request for proposal
risk management market	The market for products used by parties to manage exposure to electricity spot price risks
risk management contracts	Instruments used to change the risk position of the parties in relation to electricity prices
Rules	Electricity Governance Rules 2003
SFT	Simultaneous feasibility test
spot market	The wholesale part of the physical market for trading electricity in New Zealand where electricity generators offer electricity to the market and purchasers bid to buy the electricity. This market is also referred to as the physical wholesale market
spot price	The half-hour price of wholesale (‘spot’) market electricity
SOEs	State Owned Enterprises
SPD	The Scheduling, Pricing and Dispatch model used for operating the spot market
spread	The difference between the bid and ask price in a market
SRA	Settlement Residue Auction
TOU	Time-of-use
trading period	A half-hour period for which wholesale electricity spot prices are calculated
transmission network	A network for the transport of electricity
transparency	The ability of participants to easily access a high level of market information (trades, prices and, specifications) on a fair and equal basis
transmission customers	Market participants who pay transmission charges to Transpower
transmission hedge	An instrument for changing the locational price risk of the parties involved
Transpower	Transpower New Zealand Limited
UMR	UMR Research Limited
WMAG	Wholesale Market Advisory Group

2 MARKET BACKGROUND

23. Before the main issues and potential initiatives are considered, it is important that readers understand the electricity market, and particularly how price risk management in the electricity market works. This section provides background on:

a. The overall architecture of the electricity market;

b. The physical electricity market;

c. The market for managing electricity price risks; and

d. Participants' concerns with that market.

2.1 Electricity market architecture

24. This section describes the structure, and inter-relationship of various components, of the electricity market. (Some components, such as the markets for instantaneous reserves and frequency keeping are not covered).

2.1.1 Physical electricity

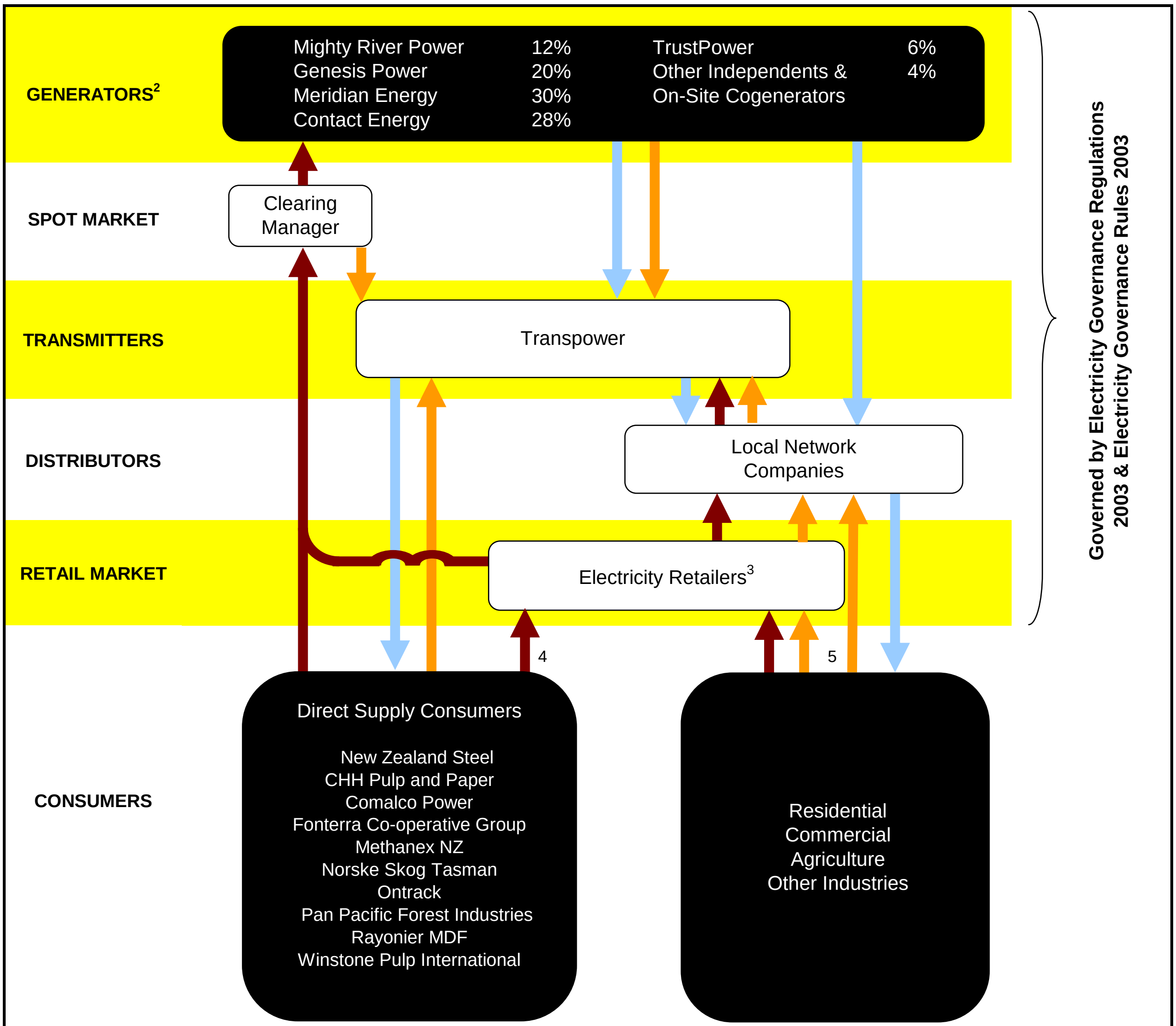
25. Electricity is supplied to consumers through a complex delivery chain. In a physical sense, electricity is produced by generators and supplied to the transmission system. The transmission system delivers the electricity to distribution networks and large consumers directly connected to the transmission network (direct connect customers). Distribution networks supply customers within their network.

26. Although electricity is physically supplied over this system, financial payments for electricity follow a different flow. Generators sell electricity to the Clearing Manager, who then sells the electricity to retailers and directly connected customers, and retailers then sell their electricity to their customers. The Clearing Manager can have surplus funds arising from the difference between the receipts from purchasers and the payments from generators that the nodal pricing methodology can create. These 'Loss and Constraint rentals' (see section 7.1.3) are returned to Transpower.

27. Retailers pay distribution companies for the use of their networks to supply retail customers. Both generators, direct connect customers and distribution companies pay Transpower for the use of the transmission network. The payments made by retailers to distribution companies also include provision for the cost of using the transmission network. Some retail customers have contracts directly with distribution companies rather than via a retailer. The payments made by retail customers also include provision for the cost of using the transmission network and the distribution network.

28. These physical and financial flows are represented in Figure 1 below.

Figure 1: Physical market



Notes:
1. Company names are listed without the suffixes Limited and New Zealand Limited where applicable.
2. Embedded (distributed) generators can choose to sell their electricity directly to retailers trading on the same grid exit point.
3. Electricity retailers include Bay of Plenty Electricity, Contact Energy, Empower (owned by Contact Energy), Energy Online (owned by Genesis), Genesis Power, King Country Energy, Mercury Energy, Meridian Energy and TrustPower.
4. Some direct supply customers use large retailers as their agents in the spot market.
5 Large industrials connected to a distribution network sometimes have contracts directly with the distributor rather than via a retailer.

Physical electricity flow
Money flow for physical electricity (excludes ancillary services)
Money flow for transmission/distribution

Both the Commerce and Electricity Commissions have key roles in the electricity market. The Commerce Commission has regulatory oversight of distribution and transmission pricing while the Electricity Commission has regulatory oversight of the retail and wholesale markets, and transmission contracts. The Electricity Commission also has contracts with service providers for market operation services such as that of the Clearing Manager.

2.1.2 Relationships between the different markets

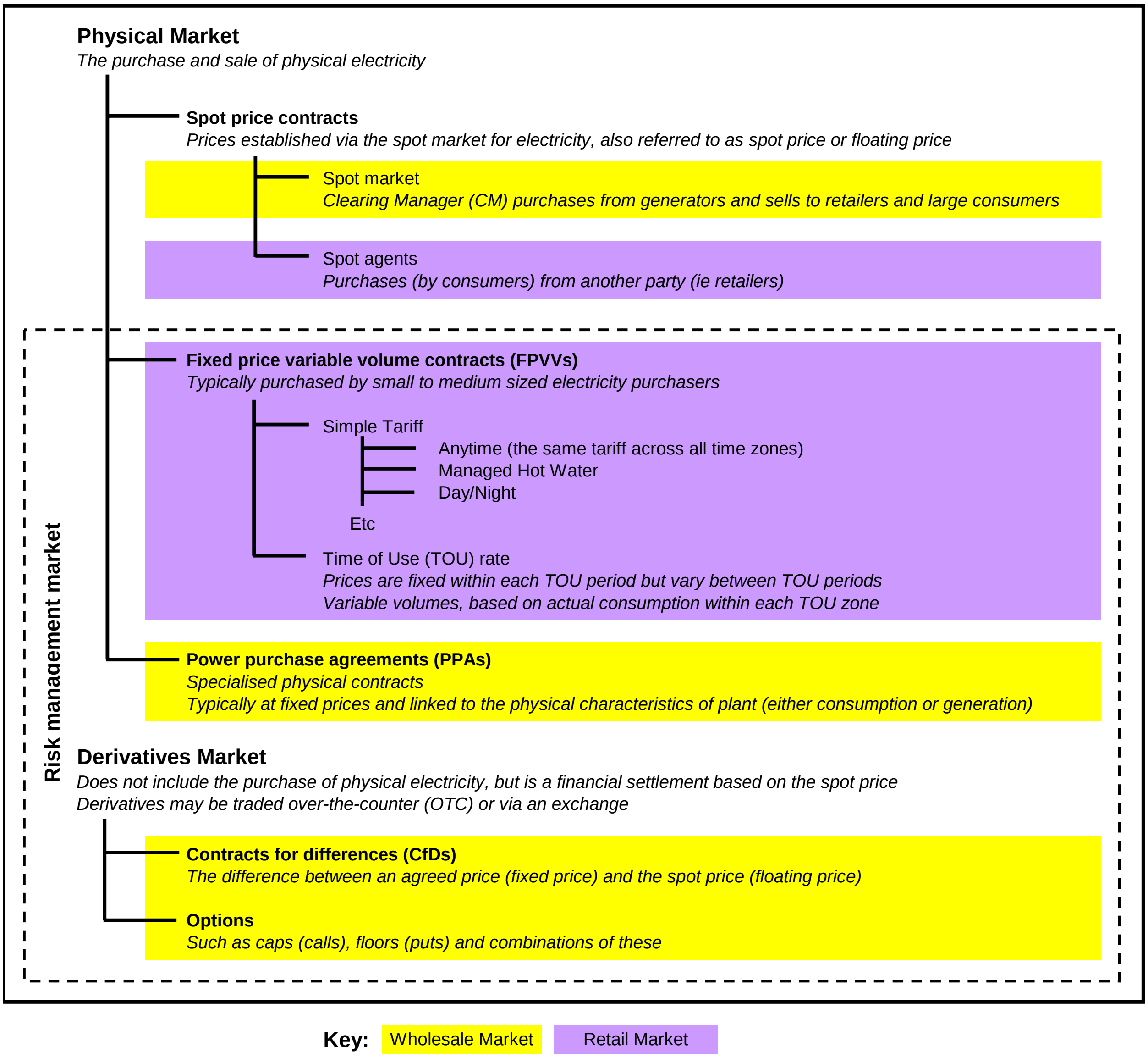
29. Reference is often made to the wholesale market, the spot market, the physical market, the hedge market, the financial market, the derivatives market and the retail market. At times it is difficult to know exactly what is meant by each of these terms.

30. For this paper, we have divided the electricity market into two parts:

- the *physical market*, which covers contracts for the supply and use of electricity; and
- the *risk management market*, which covers contracts by which parties manage electricity price risks.

31. The relationship between these two markets, and the elements within them, is illustrated in Figure 2 below.

Figure 2: Relationship between the different electricity markets



Physical market

32. The 'physical market' includes:

a. the spot market;

b. retail spot contracts;

c. fixed-price variable-volume contracts; and

d. power purchase agreements.

33. The *spot market* is most relevant to our discussion on price risk management. The spot market is discussed in more detail in section 2.2.

34. *Power purchase agreements (PPAs)* are specialised physical supply contracts between a generator and consumer. PPAs typically have fixed prices linked to the physical characteristics of the generation or load plant, but they can also have elements of spot pricing too. Meridian's contract with Comalco is an example of this type of power purchase agreement. PPAs cover about 20 – 25 percent of generation capacity in New Zealand.

35. *Fixed-price variable-volume (FPVV) contracts* are physical supply contracts between a retailer and consumer, which allow the consumer to take variable amounts of power at a fixed price per kWh. FPVV contracts generally require special conditions to avoid arbitrage when the spot price falls below the fixed price. This is normally achieved by defining the volume as all metered supply to the customer. FPVV contracts also include provisions to prevent customers from on-selling power when spot prices are high. Fixed-price variable-volume contracts are generally held by smaller consumers, such as residential, small industrial and commercial consumers. Fixed-price variable-volume contracts include retail tariffs and time-of-use (TOU) contracts

36. *Retail spot contracts* are used by some larger commercial consumers. The tariff is the spot price, plus a margin. These consumers sometimes purchase hedge cover from the derivatives market to off-set their spot price exposure.

Risk management market

37. As Figure 2 illustrates, the risk management market overlaps part of the physical market. This is because physical contracts can also be used to smooth or fix electricity prices. Hence, the risk management market comprises:

a. derivative contracts;

b. PPAs; and

c. FPVV contracts.

38. A *derivative contract* is any financial instrument whose price depends on, or is derived from, the price of another asset. Derivatives can best be considered as purely financial contracts, in that the obligation is to pay money, rather than to deliver an asset or commodity. In the context of the electricity industry, derivatives are financial contracts whose prices depend on the spot price for electricity.

39. In New Zealand, derivatives, and particularly contracts for differences (CfDs), are commonly referred to as hedges. The term "hedging" is a shortened form of the gambling term *hedging your bets*. Although technically *hedge* is a verb, in financial terminology, a hedge is a transaction conducted with the purpose of cancelling out or reducing the risk associated with an exposure (such as the need to purchase electricity at the spot price). Within the electricity market, the exposure is the purchase or sale of physical electricity at the spot price. The act of hedging is to secure an additional investment that will offset the risk of spot prices increasing (if you are a consumer) or decreasing (if you are a generator).

40. This inverse relationship for purchasers and generators risk exposure will naturally move them towards becoming counterparties for trades. For this reason, a retail base is sometimes considered to be a natural hedge for generation.

41. While *FPVV* contracts have a ‘physical’ element, they also assist purchasers to manage price risk. For example, residential consumers paying simple retail tariffs can take as much electricity as they like for a fixed price per kWh. Some non-residential retail customers pay a fixed price per kWh for a specified volume, then the spot price (plus a margin) for the rest of their consumption. Under most retail contracts, the seller can change its tariffs at relatively short notice.

42. *Time of use FPVV contracts* have different fixed prices for various time zones, and the customer is charged the different prices for consumption in each of the time zones.

43. In addition to these risk management instruments, some participants use income from other markets, such as from the instantaneous reserves market and demand management strategies to manage their exposure to spot prices.

44. The risk management market is described in greater detail in section 2.3.

Wholesale and retail distinction

45. Another taxonomy is to distinguish wholesale and retail contracts. As illustrated by the lightly shaded areas in Figure 2, the wholesale market comprises the derivatives market, power purchase agreements, and the spot market. The retail market comprises retail spot and FPVV contracts.

2.2 Physical electricity market

2.2.1 Spot market

46. The spot market manages the scheduling, pricing, and dispatch of energy and ancillary services. Generators sell power to the Clearing Manager and the Clearing Manager on-sells that power to retailers and some direct supply customers.

47. The spot market began operating in October 1996 under the New Zealand Electricity Market (NZEM) rules. On 1 March 2004, the Commission assumed responsibility for the operation of the spot market under the Electricity Governance Rules 2003 (Rules). The Commission has appointed service providers to operate the spot market.

48. The spot market establishes 5-minute indicative and half-hourly prices based on the interaction between offers by generators and purchaser demand. Hedges often refer to the spot price as the floating price.

49. Spot prices can be highly volatile due to frequent shifts in the supply and demand of electricity, and system constraints. Demand has a high correlation with economic growth in the medium term and temperature in the short term. Supply is determined primarily by the impact fuel and plant availability has on the generation offers from generators. System constraints can arise from events that affect the availability or capacity of any component of the grid, and can require a reconfiguration of the source of generation that may affect the spot price for particular nodes.

50. Spot prices are calculated, for approximately 260 market nodes, on a marginal basis – that is, the price at each node reflects the cost of providing one more megawatt (MW) of electricity to that node. This is often called *locational marginal pricing*, or nodal pricing.

51. One aspect of locational marginal pricing is that price differences occur between different nodes, creating locational price risk for parties buying and/or selling electricity at different nodes. Although this approach can provide efficient short-run pricing signals, it results in payments from purchasers exceeding the payments made to generators. This creates surplus money called “loss and constraint rentals” (rentals), which can play an important role in offsetting locational price risk. Section 7 discusses these issues in greater detail.

2.2.2 Market information flows

52. The New Zealand electricity spot market has a well-established market information system), which provides large volumes of information to market participants and non-participants about the spot market. COMIT is the IT system commonly used to access trading information. Everybody who accesses COMIT pays a fee, either directly for a subscription or indirectly through the Commission’s levy on participants.

53. Information provided on COMIT includes:

- spot price information for every trading period for 260 nodes, including forecast prices, dispatch prices, real-time (5-minute) prices, provisional prices, and final prices;
- supply and demand information; and
- hydrological information.

54. In addition, COMIT Free To Air provides summarised information to the general public for no charge. This includes hydrological graphs, final prices at eleven major locations, charts of weekly national demand and historical bids and offers.

55. Transpower (as grid owner) publishes a significant amount of information on its website regarding the national grid, including both upgrade planning information and outage planning information.

56. Transpower (as System Operator) publishes system security forecasts (updated every six months) and other technical reports on its website. Transpower (as System Operator) also publishes historical reserve prices and information on outage planning and security constraints. The System Operator issues customer advice notices to inform customers of impending changes to grid configuration, security constraints, NZ power system operation, grid equipment outages and operational security issues on an as-required basis. The Commission recently released a consultation paper to consult on the publication of customer advice notices electronically.

57. Reconciliation information (actual load) is available from the Reconciliation Manager upon payment of a fee. Historical regional and national demand is available at no cost on the Reconciliation Manager’s website at www.ems.co.nz.

58. Currently generation and transmission outage information is published by the System Operator on the redspider website[4]. The behaviour of redspider participants is governed by voluntary business rules developed by the ‘Planned Outage Forum’, which includes a “reasonable endeavours” obligation. However, there is an over-riding expectation that participants will conform with Technical Code D (in schedule C3 of the Rules) to ensure redspider contains all outage information critical to system security. Parties who wish to access the information require Transpower assistance in order to get a log-on and password.

[4] http://pocp.redspider.co.nz

59. Aggregate hydro storage and thermal fuel status is currently published on the Electricity Commission website. More detailed and timely hydrology information is published by M-co on COMIT Hydro, and is available to any party on a subscription basis. COMIT Free to Air also publishes aggregate hydrology information on a regular basis. Some generators publish relevant hydrology information on their own websites.

60. The Commission provides a significant amount of historical information as part of the Centralised Data Set. The Centralised Data Set is periodically updated, approximately every six to nine months. Information available includes:

- Half-hourly data, such as metering data, HVDC flows, active power, reactive power, generation, bids and offers, prices and binding constraints;
- Hydrology data, such as weekly hydrological inflows by catchment; and
- Transmission network configuration data, system load flow models, line diagrams and circuit breaker information.

2.2.3 Key features of the physical market

61. The physical market in New Zealand has a number of key features that affect spot market participants which need to be taken into account in considering price risk management issues. These include:

- the market being energy constrained, as opposed to capacity constrained;
- the small size of the market;
- market structure;
- the disparate location of generation and load, and the ‘long and skinny’ nature of the transmission system;
- vertical integration of generation and retail businesses;
- Government ownership of generator/retailers; and
- regulatory arrangements relevant to spot market behaviour and outcomes.

Energy constrained market

62. Many countries, such as the United States and Australia, have primarily gas, coal or nuclear power stations. Although these countries typically have sufficient fuel supplies to meet their overall electricity requirements, they can have insufficient installed capacity to meet peak demand (i.e. capacity) requirements. In capacity constrained markets high electricity prices occur primarily at peak times. During such peaks, prices can escalate very quickly. Typically, however, prices might be high for only a few hours over a long period.

63. Although New Zealand is primarily “energy constrained”, peak MW constraints can also be significant from time to time. The Commission is forecasting annual demand to grow by 2% a year of the next 20 years. In the short-term the average growth is expected to be closer to 2.7%, approximately 125MW, which is significant when large new investment is typically around 400MW. With a development trend towards wind generation, and an absence of new hydro investment, it is expected that MW constraints will be more frequent in the future.

64. New Zealand differs from a number of similar markets as it is typically energy constrained rather than capacity constrained. In contrast to Australia and the United States, the majority of electricity generation in New Zealand is hydro based (approximately 65 percent of annual generation). In New Zealand, therefore, shortages usually occur when there is limited hydro fuel to meet energy demand. It should also be

noted that prices can experience short-term spikes at times of major system outages or constraints into specific regions.

65. Some countries, such as Norway, are also predominantly hydro but have large storage reservoirs which can store the equivalent of two years of load. New Zealand, however, has very small reservoirs in comparison, and normal storage is approximately the equivalent of one month of load.

66. The high dependence on hydro generation in New Zealand, coupled with limited storage, also means that dry years can have a significant effect on the spot prices. For example, in 2001 and 2003, low inflows to the major hydro-storage lakes resulted in significant increases in spot prices. On the other hand, meeting peak demand requirements is not normally an issue in New Zealand because hydro generation can be quickly ramped up or down to meet short-term demand fluctuations. Figure 3 shows spot price fluctuations at Haywards for 23 June 2006 and Figure 4 shows the effect on spot prices of dry years in 2001, 2003 and 2006.

Figure 3 - Haywards Spot prices for 23 June 06

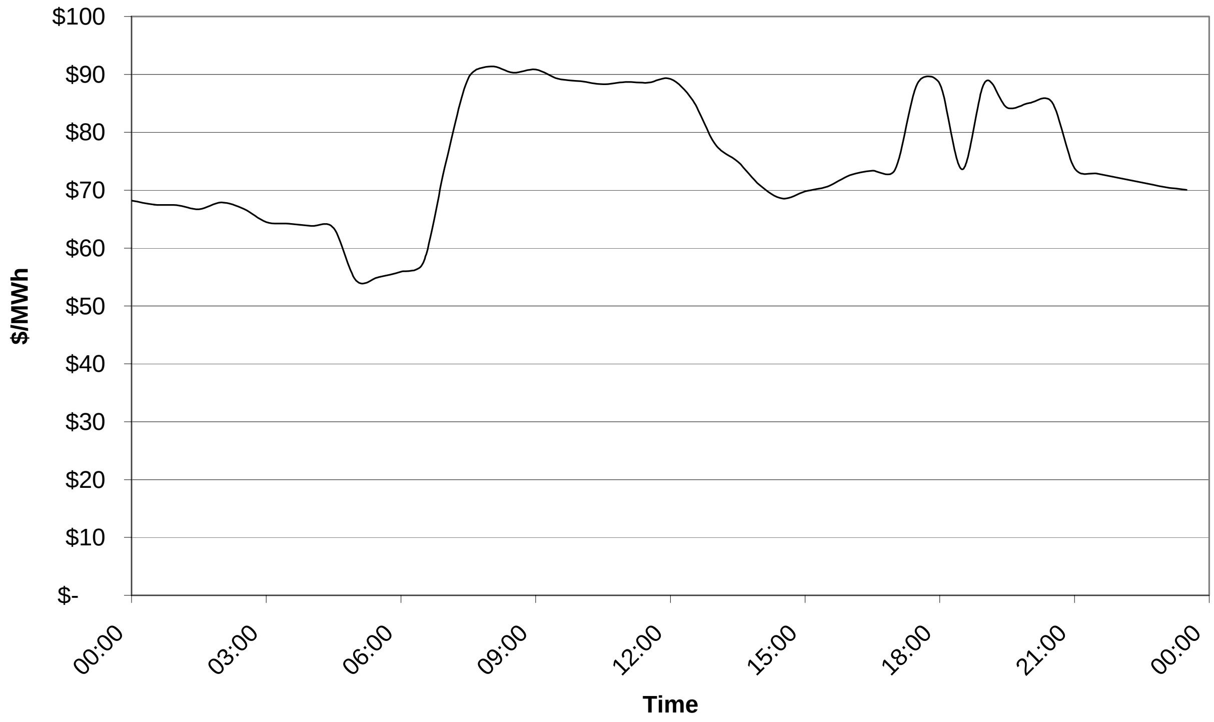
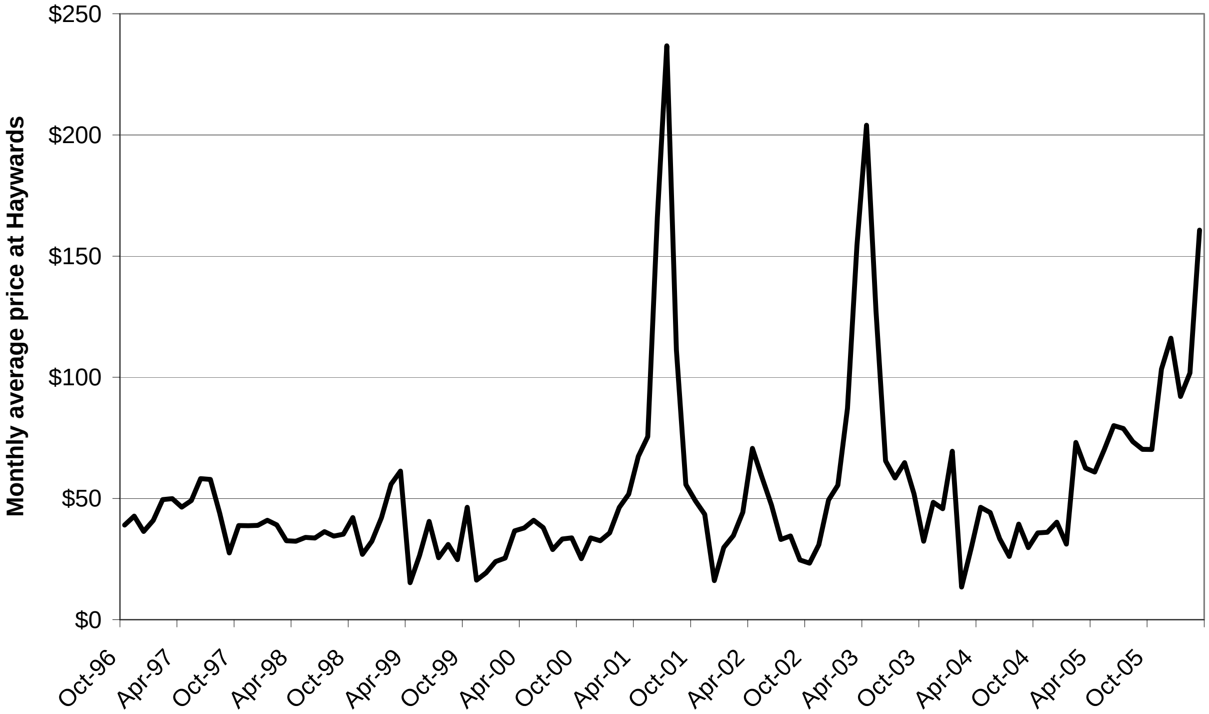


Figure 4: Monthly average spot prices in New Zealand 1996-2006 (Haywards)



67. In contrast, during fuel shortages in New Zealand, spot prices do not reach the extreme levels of capacity constrained markets. Spot prices in capacity constrained markets can reach prices in the order of $10,000/MWh, whereas prices in New Zealand during energy shortages are typically in the order of $200/MWh. New Zealand prices do, however, stay high for longer periods. In 2001, for instance, prices remained significantly higher than average for approximately two months.

68. Prices in New Zealand can reach significantly higher levels during infrequent market conditions as a result of “spring washer” pricing effects and during times of regional generation/transmission shortages. A spring washer effect occurs when the unique functioning of the nodal pricing algorithm combined with a binding transmission security constraint forces prices up on one side of the constraint and down on the other. Under a spring washer effect, nodal prices may exceed the highest offered price. The highest price in the New Zealand market resulted from a spring washer effect, and was $12,031 at the Haywards node on 21 August 2004. The marginal generator at the time was Whirinaki, which had an offer price of $1,000/MWh.

Small size of the market

69. Another key feature of the New Zealand electricity market is that it is, in global terms, a very small market. The annual generation in New Zealand is approximately 40,000 GWh/annum, with peak demand approximately 6,500 MW. In comparison, some of the other markets that have been deregulated to a similar extent as New Zealand are significantly larger. For instance:

- NEM in Australia, is approximately 195,000 GWh/annum with peak demand of approximately 28,000 MW;
- PJM (one of the major markets in North America) is approximately 700,000 GWh/annum with peak demand of approximately 131,000 MW;
- BETTA (the UK market) is approximately 390,000 GWh/annum with peak demand of approximately 60,000 MW; and

- Nordpool (the Nordic market) is approximately 400,000 GWh/annum with peak demand of approximately 60,000 MW.

70. The small size of the New Zealand market means that an outage of a large generation plant (such as a combined cycle gas turbine station) can have very large effects on spot prices, as one unit (e.g. 365 MW) is a significant proportion of total generation. In large markets, one large generation plant is only a very small proportion of total generation and has a very small effect on price. This introduces proportionally higher risks both for the owners of such generation plant in New Zealand and spot market purchasers.

71. The small size of the market also means large new generation projects can cause a surplus of power on the market and have a significant depressing effect on price for long periods. This can also mean that parties delay building generation to reduce the period over which prices are depressed.

Market structure

72. Another characteristic, related to the size of the market, is the small number of generators and retailers.

73. The five main participants in the New Zealand market are Contact Energy, Meridian Energy, Genesis Energy, Mighty River Power and TrustPower. These generators account for over 95 percent of spot market generation, measured in terms of GigaWatt-hours per annum (GWh/annum).

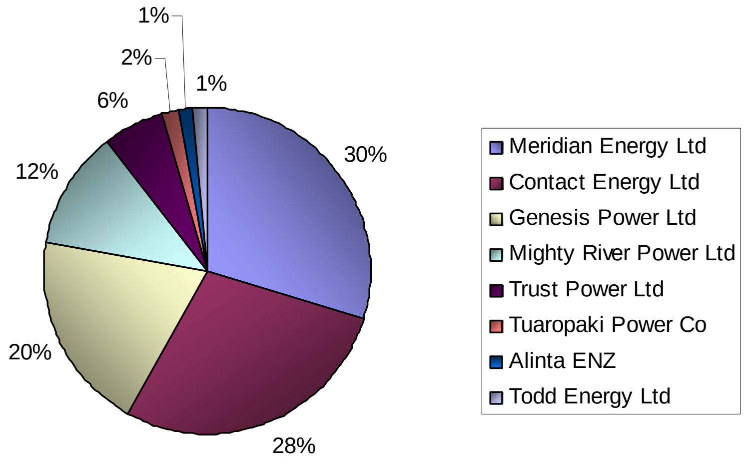
74. In comparison, approximately 51 generators participate in the Australian NEM. On a GWh/generator basis, the average size of Australian generators is approximately 3,725 GWh/annum. The average size of New Zealand generators participating in the New Zealand market is approximately 6600 GWh/annum. There are approximately 32 market customers (which include both retailers and large consumers) that participate in the Australian NEM. On a GWh/purchaser basis, the average size of Australian purchasers is approximately 6000 GWh/annum, whereas the average size of New Zealand purchasers is 4000 GWh/annum.[5]

75. There are also some small independent generators such as Tuaropaki Power Company, Todd Energy and Pioneer Generation, which comprise approximately 3 percent of total generation. NGC was a significant generator, holding approximately 7.5 percent of total generation output, but NGC sold its generation assets in 2003.

76. Figure 5 shows generator market shares for the year ended 31 March 2006, measured in terms of GWh/annum.

[5] NEMCO “An Introduction to Australia’s National Electricity Market”, June 2004.

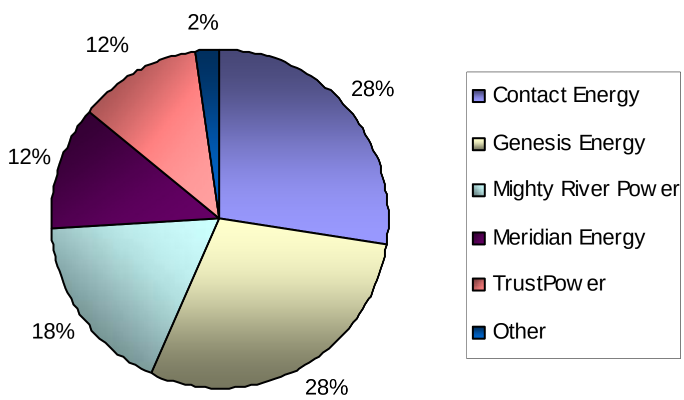
Figure 5: Generation market share (for the year ended 31 March 2006)



77. There are no independent retailers currently operating in New Zealand, although there have been in the past. Energy Online and Empower were independent retailers, but these have been acquired by major generator/retailers. On energy was at one stage the largest retailer in New Zealand, but sold its customers to Meridian Energy and Genesis Power following the 2001 power crisis.

78. Figure 6 depicts retail market shares as at 31 March 2006, calculated in terms of the percentage of installation control points (ICPs) served by retailers. ICPs are the points of supply to each customer. Retail market shares are likely to differ from the above if they were measured in terms of the percentage of GWh annum of load served.

Figure 6: Retail market share (percentage of ICPs as at March 2006)



The location of generation and load, and the nature of the transmission system

79. One important aspect of the New Zealand electricity system is the configuration of the transmission system (national grid) and the location of generation and load centres. A significant proportion of generation is located in the South Island, while the majority of load is located in the North Island. This results in a national grid that consists of long lines with a small number of routes between market nodes.

80. This configuration of the national grid can have a significant effect on spot market prices. When key transmission circuits are out of service, the prices at some nodes can

differ significantly. This results in participants who have generation (or contracts) at locations far from load facing considerable locational price risk.

81. In addition, some regions in New Zealand are prone to regional capacity constraints as a result of transmission issues. That is, at times when the margin between local load and the combination of transmission (including voltage support) and local generation is tight, high prices can occur in the region, and increase the need for measures such as load control in order to maintain supply and/or grid stability.

82. Many electricity markets also have transmission circuits that connect them with other markets. New Zealand, however, is geographically isolated, and is unable to import electricity from, or export electricity to, other countries.

Vertical integration of generation and retail

83. Vertical integration refers to situations where two businesses that operate in different parts of the supply chain are owned by the same parties and operated as an integrated business.

84. Prior to 1 April 1999, distribution and retail business were vertically integrated, with very little vertical integration between generation and retail. In 1998 the Electricity Industry Reform Act 1998 came into force. This Act prohibited vertical integration between distribution and retail. It also coincided with the split of the Electricity Corporation of New Zealand (ECNZ) into Meridian Energy, Mighty River Power and Genesis Power and has led to a marked trend towards vertical integration of generation and retail.

85. For example, in the year ended March 2006, Contact Energy had a 28 percent share of both the generation and retail markets. Genesis had a 20 percent share of the generation market and a 28 per cent share of the retail market, Meridian had 30 per cent share of the generation market, and a 12 per cent share, of the retail market, and Mighty River Power had 12 per cent share of the generation market and a 18 per cent share of the retail market.

86. Although most markets have some degree of vertical integration between generation and retail, New Zealand has a particularly high degree of vertical integration.

87. There is also a strong regional component to vertical integration. All of the vertically integrated generator/retailers have national retail operations, but have shown a predisposition towards having customers located near their generation plant. For instance Mighty River Power has generation plant in the upper North Island, and has a large market share of Auckland customers. Meridian Energy, Contact Energy and TrustPower all have significant amounts of South island generation and together have virtually all the South Island customers between them.

Government ownership of generator/retailers

88. Another characteristic of the New Zealand market is the ownership structure of the major participants. Although Contact Energy, TrustPower and Todd Energy are privately owned, Meridian Energy, Genesis Energy and Mighty River Power, which together comprise approximately 60 percent of annual generation, are all government owned.

89. The Government also owns the Whirinaki reserve generation plant, which operates in the wholesale market under instruction from the Commission. The nature of this instruction, and the resulting offer for generation at Whirinaki, relates to the hydro storage levels with respect to the Minzone, as published on the Commission’s website,

and forecast nodal prices at the Whirinaki node. Further information on the Whirinaki agreement and offer strategy is available from the Commission's website.[6]

Regulatory factors potentially affecting spot market behaviour

90. Unlike some other markets, there are no explicit or regulatory price caps in the New Zealand wholesale or retail markets. However, the spot market in New Zealand is governed by the Rules, the Act, and the Commerce Act, Spot prices are also influenced by the Commission's role in relation to security of supply, and by the Commission's approach to infeasible prices, and to allegations of 'undesirable trading situations', which may also involve the Rulings Panel.

91. The Commerce Act has the aim of promoting competition in markets within New Zealand. One of its key functions is to prohibit conduct that restricts competition in any market in New Zealand, including the electricity market.

92. The Commission is required under the Act to use reasonable endeavours to ensure security of supply. As noted above, this currently involves monitoring hydrology reserves under a 'Minzone' mechanism, and setting offer prices and quantities for the Whirinaki plant. (The current offer price for Whirinaki is $200 /MWh).

93. The Commission also has powers under the Act to address 'undesirable trading situations' (UTS). The Commission may direct that any trades be closed out, or settled at a specified price, in a UTS event. While the details of the UTS mechanism are still uncertain, it clearly has the potential to impact on spot prices.

2.3 Market for managing price risks

2.3.1 Overview

94. As described in section 2.1, the risk management market covers contracts by which parties manage electricity price risks.

95. Except for the mass retail market, the bulk of risk management contracts in New Zealand are negotiated directly between a seller and a buyer. Contracts are also sometimes obtained through a third party. This is commonly called the "over-the-counter" (OTC) market.

96. In New Zealand, OTC contracts have a large variety of terms and conditions, with each buyer negotiating particulars to meet their individual requirements. The majority of contracts are therefore highly customised and generally hard to trade, whether by standard electronic trading platform or other means. The market for contracts hedging price risks is therefore rather illiquid in New Zealand.

97. Another mechanism is *EnergyHedge*, a web-based platform for posting bid and offer prices on standardised derivatives. *EnergyHedge* transactions are still bilateral, but the parties do not know each other's identity when agreeing on a price.

98. Further discussion of the OTC and *EnergyHedge* markets is contained in sections 2.3.5 and 2.3.6 respectively.

[6] http://www.electricitycommission.govt.nz/opdev/secsupply/resenagmts/index.html#wos

2.3.2 Broader risk management mechanisms

99. In addition to the risk management contracts discussed above, there are several other mechanisms parties sometimes use to manage their electricity price risks, including:

a. vertical integration between generation and retail businesses;

b. vertical integration between load and generation, such as co-generation and stand-by generation plants owned by consumers;

c. income from other markets, such as from the instantaneous reserves market; and

d. various demand management strategies.

100. Vertical integration for generator/retailers provides risk management benefits because lower spot prices increase retail profit but reduce generation profit, and vice versa for higher spot prices. Likewise, vertical integration for generation and load provides risk management benefits because consumers can use their own generation when their generation cost is lower than spot prices.

101. Income from other markets can also provide risk management benefits. For example, consumers participating in the instantaneous reserves (IR) market receive income for having load ready to be interrupted in the case of a major generator or transmission outage. As IR prices tend to be high when spot prices are high, income from the IR market partially offsets higher costs to the spot market..

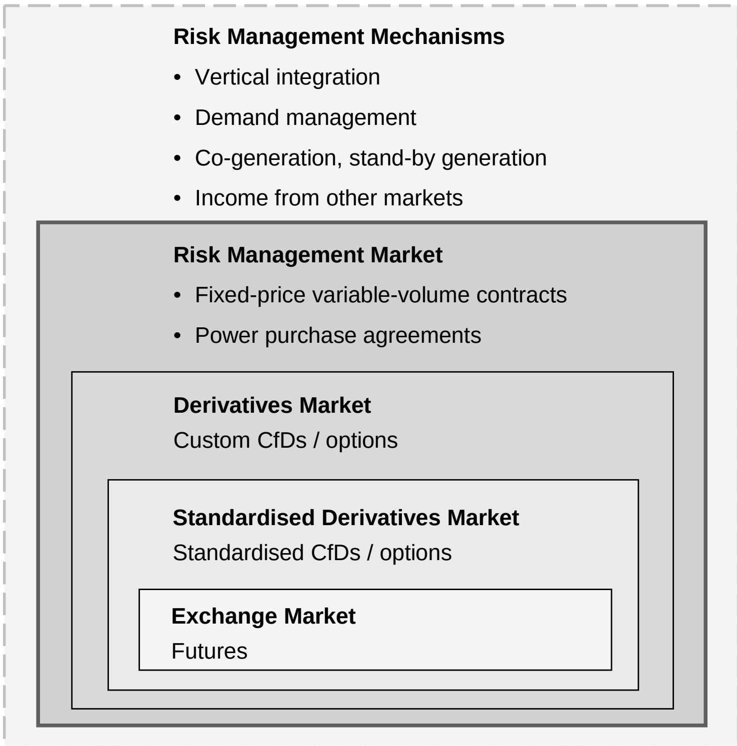
102. Finally, various demand management strategies could be viewed as risk management activity. For example, commercial consumers may install systems that automatically shut-off power to cool stores or water heaters when the spot price reaches specified levels. When grid constraints are binding, small reductions in demand can cause large spot price reductions. While this provides incentives for active demand management, the fact that the actions of a few commercial consumers may reduce spot prices for all consumers enables some parties to benefit from the action of others.

2.3.3 Risk management inter-relationships

103. Figure 7 depicts the overall setting for the risk management mechanisms discussed above:

- The outer area comprises all of the various risk management mechanisms parties may use to manage electricity price risk;
- Moving inwards, the first rectangle is the risk management market, comprising explicit risk management contracts;
- The second rectangle is the derivatives market, which is a subset of the overall risk management market;
- The third rectangle is the market for standardised derivatives, which is a subset of the overall derivatives market; and
- The inner rectangle is an exchange market, which trades futures contracts. Futures are briefly explained in Figure 9 on page 27.

Figure 7: Risk management terminology



104. Throughout the consultation paper, the terms *risk management mechanism*, *risk management market*, *derivatives market,* and *the standardised derivatives market* are used to reflect the various dimensions of risk management under discussion. These distinctions are important for understanding the problems with risk management and for analysing the economic effects of the various initiatives considered in sections 6 and 7 of this paper.

105. For example, although vertical integration is not part of the formal risk management market, various initiatives can alter the relative costs and benefits of managing risk through vertical integration versus through derivative contracts. Likewise, some initiatives may affect whether parties use FPVV contracts or derivative contracts to manage their risks.

106. In terms of the risk management market, a key area of development focus is on derivative contracts, which are discussed in detail below.

2.3.4 Derivative contracts

107. There are many types of electricity derivatives in large markets, such as in the United States or in the Nordpool market. The primary electricity derivative in New Zealand is the CfD, which is discussed in detail below. Other derivatives that are used in the New Zealand electricity market are briefly described in Figure 9 on page 27.

108. One type of derivative often discussed in New Zealand, but not yet traded, is FTRs. FTRs are discussed in detail in section 7.3.

Contracts for differences

109. A particular type of derivative that is common in electricity markets is a CfD, which is also sometimes known as a swap. A *CfD* is an agreement by two parties to exchange a

floating set of payments for a fixed set of payments. In the electricity market, the parties entering into a CfD would be locking in a fixed electricity price for a given volume.

110. Settlement on a CfD usually occurs on a monthly basis, irrespective of the duration of the contract. The payments made are based on the relationship of the fixed price of the contract compared to the spot price of electricity as determined by the spot market. If the spot price is above the contracted price, the seller of the hedge (typically the generator) pays the purchaser the contracted quantity times the price difference. If the spot market price is below the contracted price, the purchaser pays the seller the contracted quantity times the price difference.

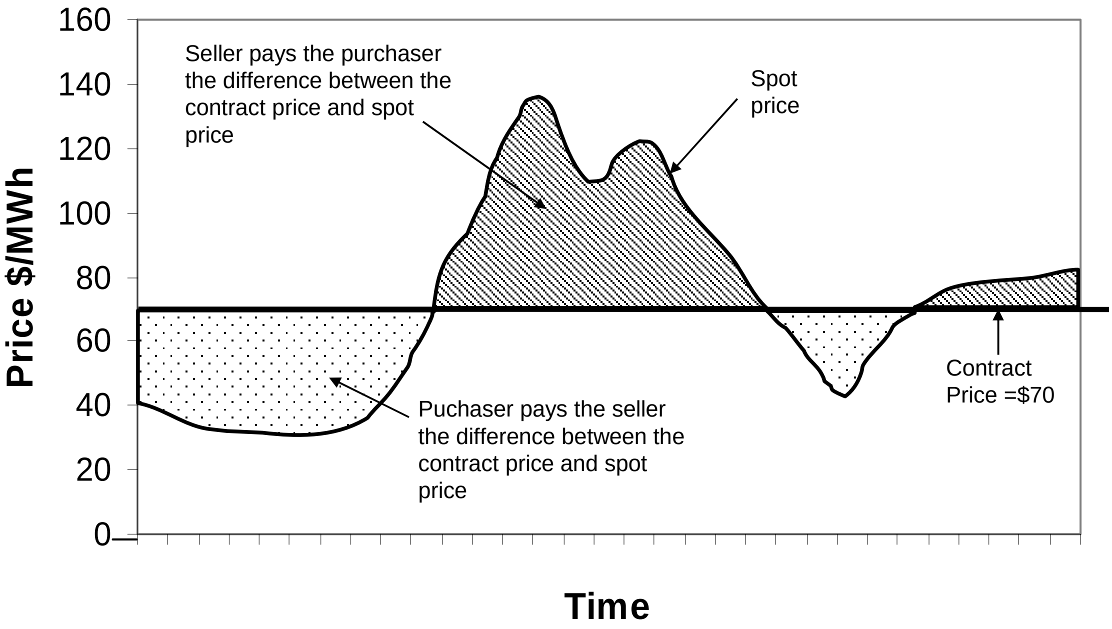
111. There are various ways that CfDs can be structured. CfDs can be for various quantities, at various locations and can be for either constant or shaped volumes. CfDs can also include Force Majeure clauses and suspension clauses.

112. CfDs can either be negotiated bilaterally or obtained via forward markets. Some forward markets are structured as blind markets, such as futures markets. Blind markets are markets where participants do not know the identity of the ultimate counterparty to their trade.. Apart from *EnergyHedge* trades, in New Zealand all CfDs are negotiated bilaterally.

Numerical example of CfD

113. Figure 8 provides a numerical example of how payments are determined for CfDs.

Figure 8: How a CfD works



114. In this example two parties have agreed to set a price of $70 (per MWh) for the contract. At first, the spot price is below the contract price of $70, the dotted area under the line. As the purchaser has agreed to pay $70, it is locked into that price. The purchaser must therefore pay the difference between the spot price and the contract price to the seller.

115. For example, if the market price is $25 and the contract price is $70, the purchaser pays the seller $45. If the spot price goes above the agreed contract price, the generator will pay the extra required to purchase the electricity in the spot market. If the

contract price is $70, and the spot price reaches $145, the generator will pay the difference of $75. The payments between the seller and purchaser are netted off over each settlement period, with a net payment made by one of the parties when the CfD matures or expires.

A key feature of CfDs

116. An important characteristic of CfDs is that, in general, they do not alter the holder's incentives to respond to spot price signals. This is in contrast to fixed-price variable-volume contracts, which also provide protection against price movements but remove financial incentives for parties to respond spot prices. This can make CfDs a more efficient risk management tool for medium to large consumers where electricity forms a high proportion of their costs.

117. For instance, in the above numerical example a consumer holding a CfD at a contract price of $70 has strong incentives to reduce demand in the spot market even though he or she is protected from the financial effects of prices exceeding $70. The reason for this outcome is that the quantity of energy covered by the CfD is fixed in the contract. It is a nominated level of energy consumption, not their actual level of consumption. Hence, holders of CfDs receive pay-outs based on the nominated quantity regardless of how much electricity they consume.

118. If a CfD holder can not reduce its electricity consumption when prices exceed $70 in the above example, then the CfD holder is well-protected financially. But if by reducing their electricity consumption a consumer can save more on their power bill for physical electricity than they lose in profits from reducing firm output levels (of course, taking into account any impacts on long-term relationships if this is important), then they have every reason to reduce consumption – they collect their CfD pay-outs and also make higher profits on their operations.

119. The one exception to this result is when an individual CfD holder can influence spot prices by changing their electricity consumption/generation. A consumer still has incentives to reduce their consumption levels down to the level of energy covered by the CfD. Beyond that level, the consumer would lose more money on the CfD than they save by reducing their electricity consumption, and will not go any further. This depends very much on how much the CfD holder can reduce spot prices and at what level of consumption this price reduction occurs. The reverse holds true, and may be even more relevant, for a generator.

Figure 9: Electricity derivatives infrequently used in New Zealand

Futures *are standardised forward contracts transacted using an exchange. The main difference between futures and other derivatives is that futures contracts are entered into between the exchange's clearing house and each of the counterparties. That is, the exchange's clearing house has sold a contract to a counterparty and bought a contract off the other counterparty (these are also known as back-to-back contracts). Parties must post prudential security to cover their risk of default.*

Options *are contracts between two parties where one party has the right, but not an obligation, to transact at an agreed price some time in the future. The agreed contract price is known as the "strike price". The buyer of the option pays the seller of the option a premium for the right to exercise the option. Options can be attractive risk management tools in electricity markets because they provide the buyer with insurance cover without locking in a fixed price hedge. There are numerous types of options, with the most basic types being call options (caps), put options (floors), collars, and swaptions (options to enter into a swap).*

Flex products *can be used to manage volume risk. Flex contracts allow one party the right to adjust the volumes of their hedge contract by an agreed quantity provided sufficient notice is given. This sort of contract typically attracts a significant premium as it provides significant flexibility for the purchaser.*

2.3.5 Trading arrangements

120. Consumers obtain electricity risk management contracts through the OTC market, or via a third party such as a broker or a web trading platform. In January 2004 the four largest generator/retailers established *EnergyHedge* for trading standardised derivatives. The objectives of *EnergyHedge*, among other things, are to achieve standardisation, accessibility, liquidity and transparency, for the benefit of participants and the electricity industry generally. So far, the five largest generator/retailers use *EnergyHedge* for direct trading of CfDs but all market participants can refer to prices observed on *EnergyHedge*.

OTC market

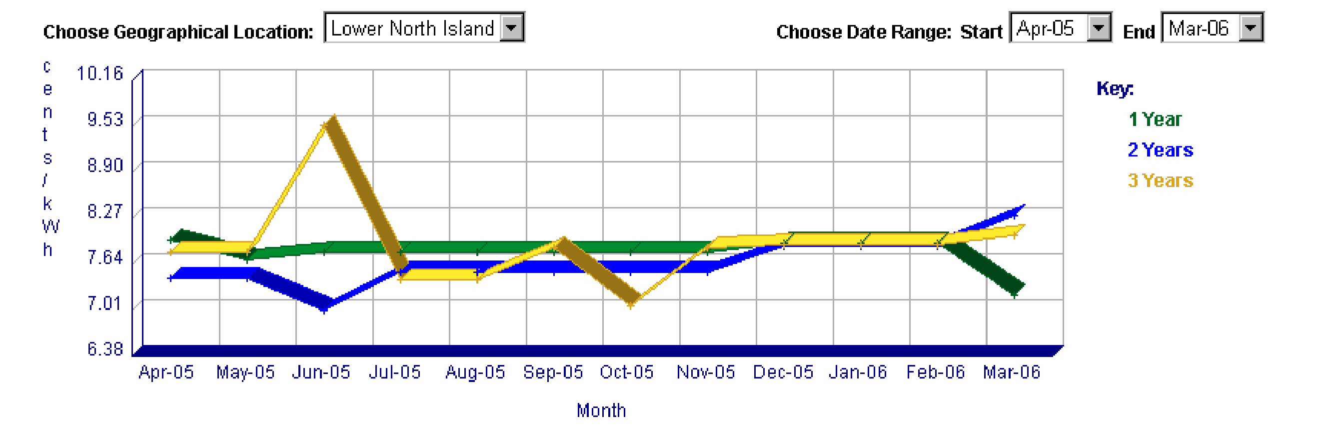
121. The OTC market is where two parties negotiate bilateral contracts directly, such as over the phone. While the substantive parts of the contract are negotiated as required, most counterparties sign master agreements that specify minor conditions to which all bilateral contracts are subject. These master agreements are normally variations of agreements provided by the International Swaps and Derivatives Association (ISDA) master agreements.

122. In New Zealand, most fixed-price variable-volume and CfDs are obtained through the OTC market. The terms and conditions of OTC CfDs vary considerably, with variations in relation to:

- quantity (in MW);
- profile (whether or not the quantity is base load or profiled, and if profiled, the shape of the profile and distribution of quantity);
- location or node;
- duration;
- product type (e.g. FPVV, CfD, or an options type product);
- price (flat price, TOU or price escalation);
- link to hydro levels in certain catchments;
- premium (in the case of options, caps, collars etc);
- pass through charges (e.g. carbon charges);
- force majeure clauses; and
- ability to generate (suspension) clauses.

123. As with other OTC markets, very little information is publicly available about OTC contract prices and volumes. Monthly average price indices are published on COMIT Free to Air, but they are a very aggregated measure of contract prices, as they comprise contracts of varying terms, for varying locations within the region, and for varying volumes. The indices also take no account of other contract terms and conditions that could be expected to affect contract prices, such as force majeure and credit risk provisions. Figure 10 shows a graph for the monthly average price index.

Figure 10: M-co fixed price index



Download Results

Duration	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06
1 Year	7.97	7.70	7.80						7.93			7.23
2 Years	7.45		7.01	7.53					7.89			8.32
3 Years	7.81		9.55	7.44		7.88	7.08	7.88	7.92			8.04

Units: c/kWh

EnergyHedge market

124. *EnergyHedge* is a web-based platform for parties to trade standardised derivatives. *EnergyHedge* participants are required to post bid and offer prices for quarterly contracts of 0.25MW, for up to 27 months ahead, and monthly contracts for the current quarter. The main purpose of *EnergyHedge* is to provide a credible and transparent forward price curve for the electricity market.

125. Contact Energy, Genesis Energy, Meridian Energy and Mighty River Power initially established *EnergyHedge* with the aim of enhancing the existing derivatives market activity in New Zealand. These foundation market-making participants wanted to enhance the electricity risk management market in New Zealand through the development of a standardised derivative contract, with the objectives of achieving, amongst other things, standardisation, accessibility, liquidity and transparency, for the benefit of participants and the electricity industry generally.

126. The founding members of *EnergyHedge* intended to provide benefits through:

   a. the creation of an accessible and transparent forward curve out to two years for electricity prices; and

   b. an increase in the transparency, liquidity, and volume of existing electricity derivatives activities.

127. Figure 11 provides a screen shot of the *EnergyHedge* market summary screen.

Figure 11: The EnergyHedge market summary screen


energyHEDGE.co.nz

Market Summary

This page will autorefresh every 45 seconds.

Top Price Movers - Last 5 business days at Wed 08:57:51

Stock	Movement	Current Price ($/MWh)	Turnover ($)
2006-M06	-32.4%	100.00	232,380.00
2006-Q03	-28.6%	95.00	791,016.00
2006-M05	-14.8%	115.00	113,739.00
2006-Q04	-10.3%	70.00	38,622.50
2007-Q01	-1.5%	67.00	146,407.75

Stock By Turnover - Last 5 business days at Wed 08:57:51

Stock	Volume	Value ($)
2006-Q03	14	791,016.00
2006-M06	12	232,380.00
2007-Q01	4	146,407.75
2006-Q04	1	38,622.50

Market Activity at Wed 08:57:51

Trades	Volume	Value ($)	Period
0	0	0.00	Today
30	36	1,322,165.25	Last 5 Business Days
44	50	1,790,050.00	Last 20 Business Days

128. *EnergyHedge* is open for trades each business day from 11am – 12 noon. The derivatives traded in *EnergyHedge* take the following form:

- Start and end dates are aligned with each calendar month or quarter;
- Contracts for the current quarter are specified in monthly lots, with longer maturity contracts specified in quarterly lots out to a maximum of 27 months;
- All contracts are referenced to the monthly average Haywards price (HAY2201);
- A minimum size of 0.25 MW, and increments are in multiples of 0.25 MW;
- Simple prices, with no other fees, indexations or pass-through provisions;
- No suspension clauses and no FM clauses; and
- Settlement on the 20th of the month with the contract counterparty.

129. Currently, only the five main generator/retailers participate in the *EnergyHedge* market. Other parties, such as banks and consumers, are able to become direct participants if they meet credit requirements and are prepared to operate on the same basis as the existing participants. To date, no other participants have joined *EnergyHedge*.

130. The existing requirements include the obligation to continuously provide a two-way price with a maximum spread of 10 percent for each of the contracts. Some parties have indicated they would like to participate in EnergyHedge if they had the ability to offer one-way trades. *EnergyHedge* members have explained the two way pricing requirements are essential for ensuring market liquidity and are a key component of *EnergyHedge*.

131. This does not completely restrict access to *EnergyHedge* because *EnergyHedge* participants are willing to trade with third parties on a non-discriminatory basis at prices referenced to the *EnergyHedge* price.

132. As at 13 March 2006, *EnergyHedge* had traded approximately 1078 contracts, representing $34 million in turnover since its inception in late 2003. Total energy contracted through *EnergyHedge* is approximately 507 GWh over a three year period, out of a total spot market of 40,000 GWh per annum. *EnergyHedge's* influence on the risk management market is greater than indicated by these volumes in terms of

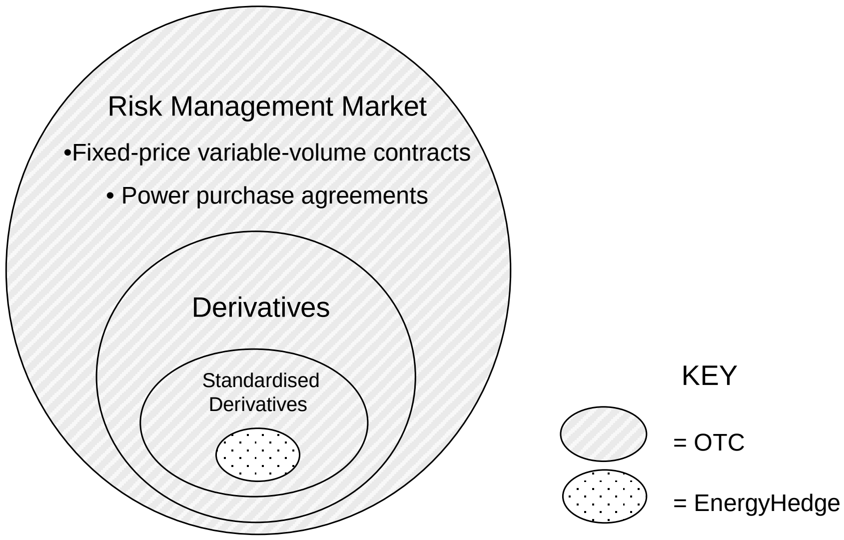
transparency, as consumers are increasingly referencing prices on *EnergyHedge* when negotiating OTC risk management contracts.

133. The primary influence of *EnergyHedge* is in how it provides information on the *EnergyHedge* participants' view of forward prices. Closing prices, which are the average of the bid price and the offer price, for each of the quarterly and monthly contracts, are able to be viewed on the *EnergyHedge* website. Historic information, including the number of contracts traded and their prices are also available on the website.

Relationship between the OTC and EnergyHedge markets

134. Figure 12 illustrates the relationship between the OTC and *EnergyHedge* markets. The lightly shaded area represents the OTC market, and the dotted area represents the *EnergyHedge* market.

Figure 12: Trading methods

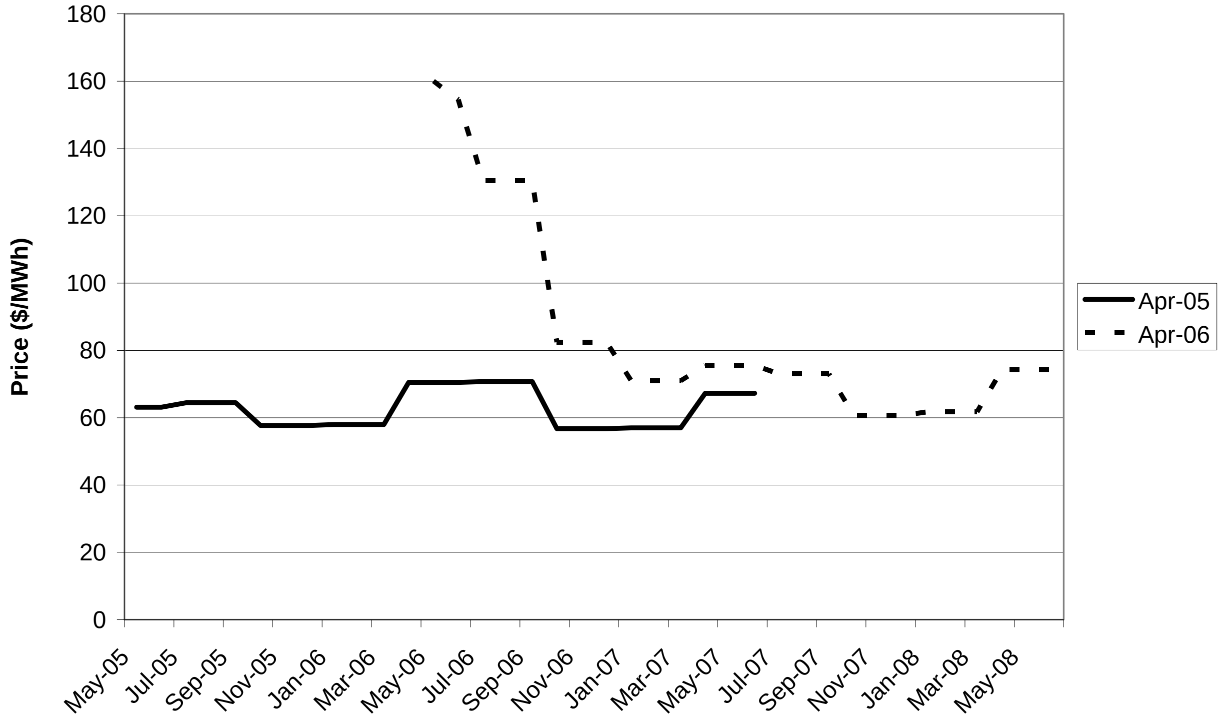


135. Although they are often referred to as markets, the OTC and *EnergyHedge* "markets" are just methods or platforms for conducting transactions.

2.3.6 Forward price curves

136. A forward price is the price today at which two parties are willing to settle a transaction at some time in the future. The forward price curve is created from the series of prices for the same product type that commence at the current spot price and continue out into the future. Figure 13 shows forward price curves derived from *EnergyHedge*; one curve uses information as at 1 April 2005, the other uses information as at 1 April 2006. Where the curves overlap, the differences in the curves are due to changes in expectations – primarily as the result of low inflows during early 2006.

Figure 13: EnergyHedge forward price curves



137. Where standardised derivatives are not available, there is a need to adjust contract prices in an attempt to create proxy standard contracts that can be used to estimate a forward price curve. Adjustments are often necessary to take account of duration, volume credit, and location. Estimated forward price curves are significantly affected by assumptions made by the party preparing them, even though they often use statistical models to achieve as accurate an outcome as possible.

138. It is common to group forward prices into convenient tradable periods, such as a monthly average price or average quarterly price. Forward prices might also be for certain periods within a given day, such as peak, off-peak or shoulder. The definition of periods will vary depending on the characteristics of the market.

139. Forward price curves indicate future spot price expectations and provide a mechanism for valuing other forward transactions. Short-term forward prices can be greatly influenced by what is occurring in the spot market. Price spikes, or even just the threat of price spikes, can dramatically affect short-term forward prices.

140. The forward price curve in Figure 13 above shows the short-term effect of the low hydro lake levels in early 2006, with derivative prices for the 2nd quarter of 2006 sitting at around $160 /MWh, much higher than the price for the 2nd quarter of 2007.

141. Longer-term forward prices tend to be influenced by environmental factors such as long term fuel supply prices or changes to technology or market regulations, because these factors drive spot prices occurring in the more distant future. The downward slope of the April 2006 forward price curve in Figure 13, for example, shows that, based on the information they had in April 2006, generator/retailers expect spot prices in 2007 to be lower than in mid 2006.

142. Forward contracts with shorter terms are more volatile than longer-term contracts. Forward contracts for periods that are likely to experience demand pressures, such as summer or winter peak periods, are also more likely to be volatile than ‘shoulder’ periods like spring and autumn.

2.4 Participants' concerns with the risk management market

143. This section sets out a range participant concerns in relation to the risk management market, as reported by the UMR survey (further detail attached as appendix A), and as gleaned from general industry comment.

2.4.1 Availability of contracts

144. Responses to the survey indicate that a number of parties (mostly purchasers) are concerned with what they consider to be the limited availability of hedge contracts. Survey respondents commented that often there are very few parties that offer hedges, and that often purchasers have very little choice regarding the hedges that are offered.

145. Purchasers also cited problems in obtaining their desired volume of hedges: rather than sourcing large volumes (10MW+), they are now having to accept smaller volume hedges (<5MW).

146. Except for *EnergyHedge,* the New Zealand risk management market has no market-makers standing ready to buy and sell contracts on a regular basis with larger consumers at publicly quoted prices. All participants in *EnergyHedge* are market-makers, but it accounts for a very small proportion of total contracts and requires participants to quote two-way prices.

2.4.2 Locational price risk

147. The UMR survey indicates that parties have a real concerned with locational price risks, which result from transmission effects on nodal pricing. The absence of a suitable hedge product by which parties can manage these risks is a key problem.

2.4.3 Perceptions of market power

148. Assertions were made in the UMR survey that market power exists in both the generation and retail sectors of the electricity market, at least in some regions and periods, particularly during dry years. Concerns have also been raised that some of the generator/retailers exercise market power in the risk management market, and that they price discriminate against industrial consumers relative to the implicit price of hedge cover provided to their affiliated retailer.

149. Both the MED and Commerce Commission have considered this issue in response to pressure from purchasers. John Small prepared a report on hedge market issues for the MED in March 2002[7] which did not reach any conclusion on whether or not market power exists. The Commerce Commission has considered market power issues on several occasions[8]; however, in no case did it determine that market power had been exercised. The Commerce Commission is currently undertaking an investigation into competition in the electricity market as a whole.

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7 Small, John, "Hedge Markets for Electric Power in New Zealand: A report to the Ministry of Economic Development", March 2002.

8 See, for instance, Commerce Commission Decision No. 491: Determination in the matter of an application for clearance of a business acquisition involving Contact Energy Ltd. and Natural Gas Corporation Holdings Ltd. and Commerce Commission Decision No. 476: Determination in the matter of an application for clearance of a business acquisition involving Genesis Power Ltd. and Energy Online Ltd.

2.4.4 Vertical integration

150. Several parties have raised concerns that vertical integration is having an adverse effect on hedge market liquidity and transparency. The concern here is that vertical integration removes trades from the market because vertically integrated entities are automatically hedged because of the common ownership of generation and retail. Concerns have also been raised that vertically integrated parties may have an unfair advantage in accessing contracts, which may discriminate against non-vertically integrated entities.

151. Another issue is that independent retailers and generators may be deterred or foreclosed from entering the New Zealand market. This foreclosure concern arises from new entrant concerns that they may not be treated fairly by incumbent generator/retailers when it comes to negotiating contracts through the OTC market, either when they first seek to enter the market or when they seek to renegotiate contracts.

2.4.5 Government ownership

152. The high proportion of government ownership has raised concerns about competition in the wholesale market. For instance, the report “Investment in the New Zealand Electricity Industry” prepared by Auckland UniServices Limited (October 2004) argues that the valuation of generation assets by SOEs has historically been too low, making it easier for SOEs to achieve a particular return on its assets compared to a similar entity whose assets are valued more highly. Recently, however, some of the SOEs have increased the valuation of their generation assets.

2.4.6 Effectiveness of contracts

153. A number of contracts include force majeure and suspension clauses. Force majeure clauses allow a party to suspend the contract following an Act of God. Suspension clauses allow a party (usually the seller of the hedge) to suspend the contract under certain conditions (such a generation outage).

154. These clauses can render a contract ineffective during the periods that are most valuable to the purchaser. It may also be argued that sellers of contracts containing these clauses also have an information advantage over the purchasers, regarding both the probability of such events occurring and the causes of such events.

155. Contracts with no FM or suspension clauses create strong incentives on the seller to effectively and efficiently manage plan. This corresponds with sellers’ stronger position to manage risks associated with plant performance.

156. Responses to the survey indicated that a number of parties (mostly purchasers, but also some generator/retailers) are concerned with the inclusion of restrictive force majeure and suspension clauses. Some force majeure clauses are viewed as reasonable, but suspension clauses are not[9].

2.4.7 Contracts with limited tradability

157. The majority of electricity contracts in New Zealand are bought or sold through the OTC market and are tailored to the specific requirements of the counterparties. In addition, a large number of customers are on FPVV contracts. This prevalence of

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9 See, for instance, the report from NZIER for MEUG “Force Majeure in electricity hedge contracts in New Zealand”, April 2005.

tailored contracts, especially FPVV contracts, makes it difficult for parties to adjust their risk position, or to determine market prices.

158. In addition, derivatives with force majeure and suspensions clauses can be difficult to trade as disclosure of these clauses will often disclose the counterparty, which may be a breach of the original contract. Secondary trading is also inhibited by the higher transaction costs incurred by parties needing to check the implications of differences in these clauses.

2.4.8 Information asymmetry

159. A key issue for a number of parties is the absence of public information on the risk management market. Some parties claim that the large generator/retailers are in an advantageous position because the array of complex information they use in their day-to-day business is often not easily or economically accessible to smaller organisations.

160. Some generator/retailers have recognised this need and provide very comprehensive online and written resources for customers to understand the issues driving the market. In addition, some generator/retailers provide courses to increase participants' understanding of risk management issues. While general upskilling is essential, it will take some time to overcome the asymmetry issue.

161. A particular concern has been expressed that fuel and plant outage information is published on different platforms, and is not provided in a manner meaningful to market participants.

2.4.9 Market transparency

162. As noted above, the vast majority of hedges in New Zealand are OTC contracts, negotiated directly between the buyer and seller. Apart from *EnergyHedge* and the infrequently updated M-co Fixed Price Contract Index, there is essentially no information available on prices or other terms and conditions.

163. Many survey respondents are concerned about this low level of transparency. A large number of respondents consider that improving disclosure is a crucial to improving the effectiveness and efficiency of the market as a whole.

2.4.10 Credit risk

164. The risk of a counterparty default, particularly for long-term contracts, is a significant concern for some participants.

2.4.11 Risk management skills

165. The UMR survey reveals that many participants have a limited understanding of electricity pricing risks, and how to manage these risks on an on-going commercial basis. Relatively few participants consider they have the skills and knowledge necessary to trade hedges. .

2.4.12 Demand-side management

166. Demand-side management is an important component of a well-functioning market. Although developments are currently underway to encourage demand-side management in the spot market, some parties note that the use of FPVV contracts

removes incentives for consumers to actively manage demand in response to high spot prices.

167. While it is argued that FPVV contracts may be appropriate for smaller users, concern has been expressed by some participants that many larger consumers, for example exceeding 1MW or 10 GWh/annum, continue to use FPVV contracts when CfDs may achieve more efficient risk management outcomes. In short, contracting for electricity is still widely viewed as a procurement function, rather than a risk management activity.

2.4.13 Generation capability issues

168. Some parties have suggested recent price rises for electricity contracts result from reductions in the surplus margin between generation and electricity demand. They also suggest a lack of generation capability in the short term, relative to demand, may be the primary reason for the perceived lack of contracts and liquidity in the hedge market.

169. Conversely, some parties note that the lack of a liquid hedge market might be the cause of inadequate generation capacity investment. Hedge contract durations are generally less than four years, but are executed in excess of 10 years, and therefore do not provide long-term price signals for generation projects which are typically 20-year investments or longer. However, they do allow parties to be able to offset short-to-medium term risk and help generators to manage price risk associated with their own generation outages.

2.4.14 Nodal pricing

170. Responses to the survey indicate that some parties believe that the large number of nodes in the spot market means that the electricity market is unnecessarily complex. In particular, some parties argue that there are more market nodes than are required and that the number of nodes should be reduced in order to make the market simpler.

171. In the context of achieving greater market transparency of hedges, there was also support for simplifying the market, particularly with respect to nodal pricing. It was argued that although the nodal price model delivers an efficient dispatch process it had effectively decommoditised electricity.

2.4.15 Prudential security

172. Some concerns have been raised that the current clearing and settlement process in the spot market does not facilitate an efficient risk management market. In particular, the Rules currently allow hedges to be lodged as prudential security upon agreement by both parties to the contract. However, very few hedges have been lodged despite strong incentives for hedge purchasers to do so.

2.5 International experience

173. In its consideration of the issues, the HMDSG investigated the extent to which other jurisdictions face, or have faced, similar issues, and what these jurisdictions have done to try and address the issues.

174. With New Zealand's small size, stringy transmission system, and concentrated generation and retail structure, it is hard to find electricity markets overseas that are highly comparable. However, markets that have a degree of similarity to New Zealand

include the Australian market (NEM), the North-eastern United States market (PJM), the Nordic market (Nordpool) and the United Kingdom market (BETTA).

175. The HMDSG prepared a paper that summarises each of these markets, along with a summary of the Chilean and Argentinean electricity industries, both of which are heavily regulated. The paper prepared by the HMDSG is available on the Commission's website at:

http://www.electricitycommission.govt.nz/pdfs/advisorygroups/hmdsg/pdfs19July05

176. A brief summary of each of the deregulated markets is set out below. Readers who would like more detail on the international experience should refer to the paper mentioned above.

2.5.1 NEM (Australia)

177. The National Electricity Market (NEM) has approximately 70 participants and operates on a gross pool basis. The NEM uses a form of zonal pricing, whereby nodal prices are calculated for each of the five main regions and fixed transmission loss factors are used within regions. Each state has only a small number of generating businesses, and vertical integration is becoming an increasingly common form of risk management.

178. In Australia, the derivatives market is unregulated and dominated by OTC contracts entered into via brokers. Market makers are incentivised to post prices with brokers having lower brokerage fees. Six standard contracts at each of the five market nodes form the majority of contracts traded. Estimates are that the derivatives market is approximately 3-4 times the size of the physical market.

179. Australia also has an electricity futures exchange, established in 2001 by d-cyphaTrade limited and operated jointly with the Sydney Futures Exchange (SFE). Historically, exchange trades have made up less than 5% of the derivatives market. Recently, however, trading volumes have increased significantly in the futures exchange, reaching 37 percent of underlying electricity demand in the first quarter of 2006. Parties who wish to trade on the exchange need to agree to abide by the rules, and pay margin calls (calls for security) when requested. Total market transparency and full information disclosure occur with all of the electricity futures exchanges discussed below.

180. Loss and constraint rentals are allocated to participants using a rental share auction whereby parties bid for a share of the total rental pool. Auction revenues are paid to the owners of transmission interconnection assets.

2.5.2 PJM (North-eastern US)

181. PJM is one of the largest and most developed electricity markets in the world. There are approximately 350 participants, with prices calculated at approximately 1700 market nodes. PJM operates on a net pool basis with a day-ahead market, a real-time balancing market and a capacity market. Approximately 50% of underlying demand is traded through the physical and day-ahead markets; the remainder is traded through physical bilaterals (outside the market).

182. Derivative contracts are predominantly traded bilaterally through an OTC market. Some exchanges are operating, but only small volumes are traded through exchanges. Standard 'peak' and 'off peak' hedge contracts (defined at 10 pricing hubs), with terms of one month to a year, are traded on the New York Mercantile Exchange (NYMEX) and the Intercontinental Exchange. There has recently been a significant increase in the number of OTC trades going through the two exchanges as a number of hedge

funds and banks have entered the market. In addition to trading standard products, some institutions are prepared to offer bilateral contracts that go out 5 to 6 years.

183. The financial market is not regulated. However, each exchange has its own rules. Parties who wish to trade on the exchanges need to agree to abide by the rules, and pay margin calls (calls for security) when requested.

184. PJM has a sophisticated FTR that allows participants to hedge against grid constraints. Auction revenue rights are issued to retailers based on their contracted firm transmission capacity.

2.5.3 Nordpool (Norway, Sweden, Denmark and Finland)

185. The Nordpool market operates on a gross pool basis and has approximately 110 trading participants. Nordpool uses a form of zonal pricing, whereby nodal prices are calculated for each of the nine main regions and fixed transmission loss factors are used within regions. Nordpool effectively has regional vertical integration where each country's generators and retailers stay and trade within their own region/s. Nordpool uses both a day-ahead market and a spot market, however recent energy issues have caused the region to start to examine capacity and dry-year reserve mechanisms. Nordpool has approximately 50% hydro generation, and there is consequently very little differential between daytime prices and night time prices.

186. Nordpool has one of the most liquid derivatives market in the world. Annual contract volumes are typically ten times the volume of annual consumption. The market is reasonably heavily regulated and includes both exchange based trading and brokers. As a result of the small differential between daytime and night time prices, all derivative products are baseload. Nordpool has stringent rules relating to information disclosure. All contract details (apart from counterparty names) are published, along with any other information that could affect derivative prices. There are a few market-makers, who compete on two-way prices to have lower brokerage and exchange fees. Constraint rentals are used to fund interconnection investment.

2.5.4 BETTA (UK)

187. BETTA operates both a day-ahead market and real-time balancing market, with a single market price for each market. The UK has a largely unconstrained grid, and locational signals are provided through locational transmission prices. The balancing rules for the market create strong incentives toward vertical integration. There are six main generator/retailers. Generation is predominantly thermal, which results in peaky daytime prices.

188. The derivatives market is not regulated, but three main electricity contracts exchanges have developed. Approximately 80% of derivative trades are executed through electronic platforms and 20% through brokers. Energy trading volume through all three exchanges is approximately two-three times the size of the physical market. The market exhibits high liquidity in the short-term, up to 12 months, but there is a dramatic fall-off in liquidity for longer-term contracts.

2.5.5 Summary

189. Each of the markets investigated by the HMDSG has some areas of similarity to the New Zealand electricity market:

- Nordpool is predominantly hydro;
- PJM uses a full nodal pricing system;

- NEM is relatively small by world standards; and
- BETTA has a high level of vertical integration.

190. Although the markets are somewhat similar to New Zealand, each of the markets has significant differences. Any lessons for New Zealand therefore need to be inferred with some care.

191. Perhaps the main lesson is the importance of understanding the context in which risk management markets operate, as each jurisdictions has widely different underlying features. Although the extent to which parties use derivatives to cover their electricity price risks, and the degree to which they trade standardised derivatives, appears to be partly related to the size of the underlying market, the design and regulatory framework also appears to be important.

192. Another lesson is the significant role that futures exchanges play in bringing full transparency to derivative trading. It is notable, for example, that Nordpool appears to have the most stringent rules relating to information disclosure for OTC trades and also the most liquid futures market.

3 POLICY FRAMEWORK

3.1 Workstream objective

193. The terms of reference require HMDSG to "provide advice to the Commission on the development and implementation of a transparent and liquid electricity hedge market".

3.1.1 What is transparency?

194. The term "transparency" is often used to describe the ability of participants to easily access high quality market information (trades, prices and, specifications) on a fair and equal basis. A highly transparent market can improve price discovery, reduce trading costs, and remove the need for intermediaries.

3.1.2 What is liquidity?

195. The term "liquidity" is often used to describe a market where contract holders can readily liquidate their holdings without depressing market prices and without incurring large transaction costs. In an illiquid market, even participants with a small share of the market face the risk that selling-down their portfolio may temporarily depress market prices.

196. The concept of liquidity is mostly relevant to markets for trading derivatives, rather than for FPVV contracts. In derivative markets, buyers can readily assimilate contract offers and integrate new contracts into their financial portfolio, or close out a position if their view of the market or circumstances changes. With an FPVV contract, they are limited by the requirement that they accept physical delivery of the product.

197. Market liquidity can be measured in terms of:

a. market depth, which is the volume of contracts available for trade at any point in time;

b. spread, as measured by the difference between the bid and offer prices for a contract; and

c. the volume of trading activity.

198. To achieve an acceptable level of liquidity, derivative markets typically need to trade at levels well above the volume of the corresponding physical market. As noted above, in the Nordpool market, trading of standardised derivatives is about ten times larger than the level of electricity consumption.

199. Low liquidity is not necessarily a function of inadequate competition. It tends to occur when the underlying market has a small number (or volume) of trades, when risk management activity is spread across multiple instruments rather than concentrated in one market, and when demand for risk management services is low. These factors are discussed in greater detail below.

3.1.3 Is liquidity a realistic goal?

200. In competitive risk management markets, participants have appropriate incentives to adopt arrangements and terms that best meet their risk management needs. The optimal form of risk management typically varies for each participant, and may range from general risk management strategies (such as vertical integration, stand-by generation, demand-side management, and trading of CfDs), to more general market activities (such as fixed-price variable-volume contracts and non-standard CfDs), through to highly specialised market activity (standardised CfDs and options). Often parties obtain the best result by selecting a mixture of risk management practices. Depending on the mix of strategies adopted, high levels of liquidity may not be achievable in specific risk management forms.

Uncertainty about the potential size of the New Zealand derivatives market

201. A key question is whether the New Zealand context is large enough to sustain a highly liquid derivatives market.

202. As noted above, many of the electricity markets in the United States are very large and yet have relatively illiquid derivatives markets. The derivatives market in the United Kingdom is distorted by the balancing regime it has in place for the spot market. The Australian derivatives market is stimulated by strong retail competition and fixed location factors that significantly reduce location risk, which allows greater standardisation of contracts.

203. Nevertheless, even relatively small markets can have very liquid derivatives markets. For example, total electricity consumption in the Nordpool countries is approximately half that of PJM, but their derivative market is probably the most liquid market in the world. As noted above, the Nordpool market typically has an annual contract volume ten times the volume of annual physical consumption.

204. The Australian electricity market is also relatively small in world terms but their electricity futures market appears to be gaining momentum. As noted above, trading volumes in the first quarter of 2006 reached 37 percent of underlying electricity demand, which is a significant lift from earlier years. Also, the level of open interest is now exceeding 32 million MWh, which is 16 percent of underlying electricity demand.

205. Given the difficultly in finding an electricity market overseas that is highly comparable to New Zealand, and given that buyers in the New Zealand market tend to view electricity as a procurement function (rather than an on-going risk management activity), it is hard to gauge the potential demand for derivatives in New Zealand – it could be large relative to our underlying physical market (as in Nordpool), or it could be relatively small as it is now. The fact that many consumers already have a hedge in the form of a FPVV contact could indicate that the demand for derivatives in New Zealand may be limited.

Determinants of liquidity

206. According to a report by NERA Consulting, prepared for Contact Energy in 2004 (NERA Report) [10], liquidity in the derivatives market will depend on several factors, including:

- the structure of the generation sector, particularly in terms of the make-up and types of available generation capacity;

[10] Graham Shuttleworth and Tim Sturm, "Hedge Markets and Vertical Integration in the New Zealand Electricity Sector: A report for Contact Energy", NERA, October 2004

- the sophistication of the existing financial markets;
- the sophistication and skills of participants;
- the size of the market and the number of participants;
- the underlying volatility in demand and severity of weather changes; and
- the level of vertical integration between generation and retail.

207. In particular, a market that has changeable conditions and new information arriving regularly is likely to be good for liquidity since it is likely to prompt parties to frequently trade contracts to adjust their risk position. In New Zealand, regular changes in hydrology and constraints on the grid seem to fulfil this condition.

208. According to the NERA Report, the New Zealand derivatives market may be unable to reach a high level of liquidity because:

a. there is a poor knowledge about hydrology risks and parties may underestimate the degree to which risk management is required;

b. there are only a small number of parties who are likely to use wholesale risk management products (i.e. hedges);

c. the high variation in consumption patterns means that it will be difficult to develop standard products that will meet the needs of participants;

d. there is a lack of transmission risk management arrangements, and so there is a strong incentive not to have standardised contracts;

e. the possibility of Government intervention, and particularly the reserve generation scheme, acts as a disincentive for risk management; and

f. there is limited development of standardised contracts.

3.1.4 Policy objective

209. Clearly, a liquid market can bring many commercial and economic benefits for market participants, including low transaction costs and confidence they can alter their contract positions if their circumstances change. If trading information is publicly available, a liquid market would also produces a robust forward price curve, providing a robust basis for parties to value their contract portfolio. The emphasis on liquidity in the GPS and HMDSG's terms of reference is therefore understandable.

210. However, given the uncertainties outlined above, other goals have been considered, in addition to liquidity that more fully reflect the Commission's principal objectives and specific outcomes (set out in section 1.2 above).

211. The HMDSG recommends that the policy objective should be to promote a well-functioning market for instruments used by buyers and sellers to manage their price risks efficiently.

212. The next section discusses the fundamental elements of a well-functioning risk management market.

3.2 Fundamentals of a well-functioning risk management market

213. The HMDSG identified four fundamental elements for a well functioning risk management market:

a. a competitive underlying physical market;

b. sound rules and standards;

c. appropriate infrastructure, covering both technical and human factors; and

d. high quality information and efficient information flows.

214. These four elements are discussed below.

3.2.1 Competitive underlying physical market

215. Derivative markets have an intrinsic relationship to the associated underlying physical market, as derivative payments depend on prices in the underlying physical market.

216. The competitiveness of the underlying physical market affects confidence in the related derivatives market. For example, participants will be extremely reluctant to buy derivatives from a party that can exploit temporary opportunities to move the physical price against them, leaving the derivative holder 'out of the money'. Confidence in the competitiveness of the physical market is therefore vital to creating a vibrant derivatives market.

217. Prices in the derivatives market reflect perceptions about the future of the underlying physical market, which means inefficiencies in the underlying physical market carry through to the derivatives market. Even if the derivatives market is perfectly competitive, any market power in the underlying physical market is likely to flow through to create price distortions in the derivatives market.

3.2.2 Sound rules and standards

218. Sound rules and standards are critical to the development of an efficient market. Rules and standards provide certainty for participants in knowing what is required for them to participate, what to expect from the market operator and other participants, to what extent any legal and/or regulatory risk is already being addressed, and to what extent parties need to make their own arrangements to address legal risks.

219. Rules and standards provide the framework for exchange of goods and services to occur, and having sound rules and standards facilitates efficient trade. However, the benefits of rules and standards need to be balanced against the costs they may impose, particular in relation to innovation.

Standards

220. Standards provide a framework for participants to compare products, which lower transaction costs. Standards often start as trade practices, and evolve to become voluntary standards that participants are expected to comply with, unless parties to the transaction agree not to.

221. The power of standards to facilitate efficient market development should not be underestimated. In most derivative markets, parties trade customised products, but

over time their trade gravitates toward standardised products as sophisticated instruments are developed to deal with idiosyncratic risks.

222. Trading standardised products greatly reduces transaction costs, as the participants know exactly what they are buying and selling. This facilitates continuous trading, which in turn facilitates efficient price discovery.

223. More generally, efficient financial markets require widespread adherence to high quality accounting and reporting standards. Having high quality standards is not enough – it is only when they are applied diligently and consistently that participants can have confidence that the financial information is meaningful and useful.

Rules

224. Rules go a step beyond standards in that compliance is mandatory not voluntary. Rules are primarily used to protect the property rights of participants in a specific market, or to deal with situations where parties can 'free ride' on the actions or investments of other parties.

225. Efficient rules facilitate efficient coordination of the market, and bring low transaction costs. This makes economic sense when non-compliance with a standard imposes costs on multiple parties participating in the market.

226. The binding nature of rules governs the interaction of participants and provides them with greater certainty about each other's behaviour. Efficient rules create certainty for participants, reduce risk and build confidence. A well-functioning market is not possible without certainty about other parties' behaviour, or without confidence that the rules will be upheld.

227. Rules may evolve as market conditions change. Simple rules facilitate coordination of the market, which in turn leads to greater participation if they are well specified and enforced. As more parties participate and become familiar with the rules, the rules can be tailored to enhance efficiency, which in turn leads to greater participation. Sometimes rules can be relaxed or made less specific as markets mature. For example, in some markets, very specific process-based rules have been replaced with outcome-based rules over time.

228. Often there is competition between markets with different rules and standards – for example, between commodity and equity markets. Over time, the market with the most efficient rules and standards becomes *the* market for that particular product or service.

3.2.3 Appropriate technical and human infrastructure

229. Appropriate technical and human infrastructure is also fundamental part of a well-functioning market.

Technical

230. Technical infrastructure refers to any technical mechanism that supports the market. In today's environment, such mechanisms are usually IT related, and can include infrastructure related to the operation of the market (such as trading platforms) as well as infrastructure used by participants to value positions, examine the underlying market, value alternatives and interact with the market,.

Human

231. Human infrastructure refers to people with the appropriate skills and abilities required for organisations to be able to understand the market and operate effectively in the market. Markets that are complex require participants to have greater skills and knowledge about that market in order to be a successful participant.

232. Trading staff and senior management require a minimum level of competency to efficiently participate in derivative markets, and the more complex are the products traded the higher the minimum level of competency. If participants do not understand how the market works, they are unlikely to be able to participate at the level required to ensure efficient decision making and information transfer.

233. A significant issue relating to infrastructure is that participants need to have a high level of confidence in the market in order to invest in higher levels of technical and human infrastructure. If participants consider that a market is not working, they are unlikely to use the market and unlikely to invest in infrastructure to do so. This has a follow-on effect in that without appropriate infrastructure, the market is unlikely to work efficiently, and prospects for the development of an efficient market are diminished.

3.2.4 High quality information and efficient information flows

234. High quality information and efficient information flows are also essential, particularly to efficient pricing, monitoring, and protecting the integrity of rules. Indeed, transparency, with high quality information and analysis, is the lifeblood of a well-functioning market.

235. For example, the bidding and offering behaviour of participants and the resulting prices reflect information known to the participants at the time they make their bids and offers. In an efficient market, prices reflect all relevant information that is available at the time. Timely and accurate information flows are therefore vital to achieving efficient pricing outcomes.

236. Conversely, lack of access to accurate and timely information, or unequal access to such information, can distort prices and lead to inefficient decision-making and an overall lack of confidence in the derivatives market.

237. Organised markets can enhance market efficiency through mandating information disclosure, and by providing the infrastructure to share this information. The goal is to provide participants with accurate, timely and non-discriminatory access to information.

238. Full and timely disclosure of price-sensitive information is critical for removing opportunities for insider trading. Suspicions of insider trading undermine confidence in the fairness of the market, and erode participation in the market. Strict enforcement of information disclosure requirements, and vigilant monitoring and policing of insider trading activity, is a necessary requirement of successful derivative markets.

239. Another way of looking at insider trading in relation to derivatives markets is to assume that the prices of derivatives reflect “insider information” that participants have. Consequently, these markets are designed for participants to take positions and make profits based on the “inside” information they possess. The act of taking positions conveys the price relevant content of the information to the market as a whole. This is still an efficient mechanism, but its efficiency does rely on the underlying physical market having good information disclosure.

240. Insider trading rules in relation to futures markets are usually different than for share markets. The insider trading rules in derivatives markets are typically designed to stop people taking advantage of “inside” information of others, such as rules against brokers and dealers piggy-backing or front-running client orders.

241. Despite the differences in derivatives markets, full disclosure of bidding and offering activity, and market trades, is critical for facilitating a transparent market. Total transparency underpins confidence that market processes are fair, and that the rules are applied with equal vigour to all participants. Total transparency puts the spotlight on market operators to operate with the utmost of integrity, and to speedily address infractions whenever and wherever they occur.

242. However, information disclosure does not always enhance efficiency and care must be taken not to allow or mandate the disclosure of information that could undermine efficiency, for example by allowing participants to tacitly collude.

243. There is also a balancing act involved in protecting the private interests of information providers and the public interest of market participants, market commentators, and market observers. Information providers invest time and resources to acquire and dispense information created from the raw market data, and need to continually evolve their systems as new technology becomes available and as the needs of participants change. Centralising and publishing all information lowers short-term costs but may reduce the value that these information providers can deliver to their customers.

3.2.5 Conclusion

244. The small size of the New Zealand electricity market, and the inevitably small number of participants in that market, means that an efficient New Zealand derivatives market may not result in high levels of liquidity. For these reasons, it is critical to focus on improving the fundamentals for an efficient market, rather than using the liquidity level as the sole measure of success

245. There are two approaches to building the fundamentals. One approach is to regulate significant changes that dictate how buyers and sellers should manage their price risks. However, there is a high risk that making such changes will have unintended consequences and not lead to the desired outcomes. This approach also risks prescribing processes that do not meet the needs of buyers and sellers.

246. The other approach is to adopt an evolutionary approach, and implement more targeted changes that have limited risk of unintended consequences and a higher probability of improving the performance of the market.

247. Developing derivative markets requires participants to have confidence in the integrity and competitiveness of the market, but it is not possible to directly regulate confidence – the focus of regulation needs to be on market foundations that underpin confidence. Adopting an evolutionary approach is more likely to grow confidence and does not mean that initiatives requiring significant changes will not be implemented. Indeed, an evolutionary approach may mean that the market develops a number of initiatives that would be similar to those that would have been regulated, without the additional costs imposed by regulation.

3.3 Key problems with the risk management market

248. Drawing on participants' concerns (as set out in section 2.4), the HMDSG has boiled down the key problems in the current electricity risk management market.

3.3.1 Lack of robust information

249. A large amount of information is available on the physical electricity market. However, limited information is publicly available in relation to the risk management market.

250. While some generators/retailers provide information to their customers, there is a general lack of timely and robust information about contract volumes, prices, and key contract terms and conditions. This information is crucial for participants to formulate meaningful views on expected future prices. Useful forward price information comes from (among other things) disclosure of recent contract prices, and active secondary trading (or at least pricing) of contracts.

251. With extremely limited information from the OTC market, it is not possible for market participants to develop robust views of forward prices.

252. The Fixed Price Contract Index published by M-Co has limited value for risk management market participants. In particular, it provides only a very coarse measure of market prices, is published only once a month, and contains information relating to FPVV contracts. Most market participants therefore consider it has virtually no relevance in making hedging decisions.

253. *EnergyHedge* provides a highly transparent forward price curve, but it covers only a very small volume of contracts. Some observers argue it is therefore of limited relevance. On the other hand, some generator/retailers say that their customers are often using it as a reference in bilateral negotiations.

254. Information on fuel levels and plant outages is another problem area. As noted in section 2.2.1, the redspider website plant outage information is provided with a security of supply focus on a voluntary "reasonable endeavours" basis. In addition, the format of redspider information makes it hard for some market participants to interpret the impact outages are likely to have on spot prices. For many parties (particularly non-generator/retailers), the current fuel and outage information is of limited use in making hedging decisions.

255. This overall lack of timely, relevant, and high quality information undermines confidence in the risk management market, which in turns deters parties from using derivatives, preferring instead the 'safe haven' of vertical integration and FPVV contracts.

3.3.2 High participation and transaction costs

256. Another key issue is the predominance of customised contracts with (among other things) different force majeure and suspension clauses. These contracts are hard to trade, which makes it difficult for parties to adjust their risk positions in the light of new information about market conditions or their own circumstances.

257. The lack of low cost access to standardised derivatives leaves participants with more limited risk management options than are available in several other jurisdictions. *EnergyHedge* offers a standardised derivative, but as noted above it is not widely

used. Some argue that without the option of a more directly accessible standardised derivative, it is difficult to be confident that participants are using the most efficient mix of instruments, and that the risk management market is dynamically efficient.

3.3.3 Lack of confidence in the competitiveness of the risk management market.

258. Several of the concerns raised by market participants reflect an underlying problem with confidence in the competitiveness of the risk management market. This is evident from the issues raised in section 2.4 regarding market powers, vertical integration, the availability of contracts, the effectiveness of contracts, information asymmetry, and market transparency.

259. In relation to the competitiveness of the *EnergyHedge*, which is still a very small component of the wider risk management market, it is possible to take two starkly differing interpretations:

a. One interpretation is that *EnergyHedge* participants offer highly competitive prices, as the contracts are highly standardised and referenced to prices at a single node. The discipline of providing two-way prices ensures no ability to promote misleading price information; and

b. The other interpretation is that *EnergyHedge* provides a platform for generator/retailers to collude on prices. As the volumes available on *EnergyHedge* are very small relative to the total risk management market, and as participation requirements effectively make *EnergyHedge* closed to direct participation by other parties, generator/retailers could be using it as a low-cost mechanism to signal among themselves what they consider to be the appropriate base price for energy. Each of them can use this information to price contracts in the OTC market.

260. To be effective, tacit collusion normally requires the colluders to be able to observe the prices set by other colluders (in the OTC market, in this case) and a mechanism to punish defectors. Lack of transparency in the OTC market suggests defectors can neither be observed nor punished. Nevertheless, there remains uncertainty as to whether *EnergyHedge* is as competitive as it is made out to be.

261. These concerns do not necessarily mean there is a market power problem, but at the very least there appears to be widespread suspicion among risk management market participants, including some generators, that generator/retailers exercise market power in the risk management market, and perhaps also in the spot market and the retail electricity market.

262. These suspicions have a corrosive effect on the risk management market, by undermining interest in participating in the market, encouraging parties to lobby for 'political insurance', and creating an uncertain regulatory environment for all concerned. These effects reach far beyond the risk management market, through to whether the spot market is politically sustainable over the long term.

263. The problem for the hedge market workstream is that it is difficult to determine with a high degree of confidence whether the competitiveness concerns are real or misperceived. Lack of information on OTC trades, and the limited degree of contract standardisation, makes it very difficult to compare contract prices.

264. The Commerce Commission has undertaken several investigations into the competitiveness of the electricity market. Following the 2001 dry year and the exit of

the retail market by On Energy, the Commerce Commission considered the competitiveness of the wholesale and retail electricity markets. It reached the conclusion that Genesis Power did not exercise market power, but that there was insufficient evidence for it to be able to conclude whether or not Meridian Energy exercised market power[11]. The Commerce Commission also considered market power issues in relation to the purchase of EnergyOnline by Genesis Power in 2002, and gave an authorisation for that transaction to proceed[12]. The Commerce Commission has recently started an investigation into the competitiveness of the generation and retailing markets under part 2 of the Commerce Act.

265. Although an investigation is currently underway into the competitiveness of the generation and retail markets, it is important for market participants to form their own views on competition by interpreting all the information sources they have available. The long-term prosperity of the risk management market is best fostered by initiatives that bring day-to-day transparency to market trades.

3.3.4 Lack of suitable mechanisms to manage location price risk

266. Another fundamental problem with the current risk management market is the lack of suitable mechanisms for market participants to manage their location price risks. This fosters inefficient use of derivatives because it constrains participants from adopting more standardised contracts referenced at central nodes.

267. Currently, consumers close to the main generation hubs manage their locational price risk by obtaining bundled contracts covering both energy and location risk. But consumers at nodes distant from the main generation hubs often struggle to obtain transmission hedges covering their locational price. The challenge is to find an effective, pragmatic, and cost effective solution to the lack of transmission hedges.

3.3.5 Lack of understanding of electricity risk management

268. As discussed in section 3.2, human infrastructure is an important prerequisite for effective and efficient financial markets. The UMR survey identified that many electricity industry participants have a limited understanding of the benefits of using derivatives to manage their electricity price risks.

269. In particular, many of the survey respondents indicated a preference for negotiating medium- to long-term fixed-price variable-volume contracts, which they can ‘tuck away in their bottom draw’ until the contract nears maturity. In essence, electricity contracting is widely viewed as a procurement function rather than a risk management activity. There seems to be limited appreciation that FPVV contracts restrict flexibility to manage price risks.

270. A further impediment to risk management market development is the view held by some parties that energy price risks can be managed by political rather than commercial actions. That view, and the political activity that stems from it, can lead to pressure being placed on officials for regulatory solutions that would not be required if a transparent and robust derivatives market was functioning in New Zealand.

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[12] Commerce Commission Decision No. 476: Determination in the matter of an application for clearance of a business acquisition involving Genesis Power Ltd. and Energy Online Ltd.

271. The existence of the Whirinaki reserve generation plant, and the underwriting of Genesis' gas contract for E3P plant, may have reinforced the belief by some that risk management using derivatives is an unnecessary complication to the main thrust of their business activity.

4 EVALUATION FRAMEWORK

272. Before any potential initiatives are identified and analysed, it is important to outline the framework for evaluating them. This section sets out the features that risk management initiatives should seek to achieve, and the criteria against which they should be evaluated.

4.1 Desired characteristics

273. As outlined above in section 3.1.4, the overall policy objective is to promote a well-functioning risk management market – this is the market for instruments that buyers and sellers of electricity use to manage their exposure to changes in spot prices.

274. Characteristics of this market in a well-functioning form include efficient:

- disclosure to the market of essential information relating to the underlying physical market and the sale or purchase of risk management instruments;
- availability of risk management instruments at efficient market prices;
- (low) costs of trading risk management instruments, within well-designed market rules;
- comparability of prices and other key terms;
- understanding by market participants of electricity pricing risks and how to manage those risks; and
- market-making and broker activity.

275. As discussed in section 3.1.3, liquidity is not, in itself, the primary measure of this market's success in New Zealand. Whether the market is successful is better gauged by the set of factors listed above.

276. Lower barriers to retail market entry, greater competition in the spot market, and enhanced security of supply are flow-on benefits of a well-functioning risk management market, which have been taken into account in the evaluation framework.

4.2 Evaluation criteria

277. A well-functioning risk management market would contribute significantly toward improved allocative, productive and dynamic efficiency. These well-established criteria can therefore be used to evaluate how well possible initiatives would help to achieve the objective.

278. The HMDSG used an evaluation framework that includes economic costs and benefits (including administrative and compliance costs), the timeframe for implementation, certainty of net benefits, and inter-dependencies and linkages.

4.2.1 Economic costs and benefits

279. One of the most important aspects of any initiative is the way in which it affects economic efficiency. Most initiatives have a mixture of effects, reducing efficiency on some dimensions and increasing efficiency on other dimensions. Increases in efficiency are counted as economic benefits, and reductions in efficiency are economic costs.

280. Economic efficiency is normally considered under three categories:

a. *Allocative efficiency*, which is the extent to which the initiative facilitates allocation of resources to their most valued use. Allocative efficiency in the risk management market would occur when each party obtains an efficient level of risk cover;

b. *Productive efficiency*, which is the extent to which the initiative encourages parties to produce goods and services at minimum cost[13]. Productive efficiency in the risk management market would occur when parties use an efficient mix of risk management mechanisms; and

c. *Dynamic efficiency*, which is the extent to which the initiative facilitates efficient investment and innovation over time. Dynamic efficiency in this context would occur when risk management techniques and trading arrangements evolve efficiently over time.

281. The above categorisation of economic efficiencies is taken into account in the cost-benefit analysis, although the evaluation does not list each separately.

282. Initiatives in the risk management market will often affect behaviour in other related markets, such as the physical wholesale and retail markets. Where relevant, these wider economic efficiency effects are included in the evaluation of initiatives in sections 6 -8.

283. Another key aspect of any proposal is the level of administration and compliance costs associated with it. These costs can be categorised into:

a. The costs of establishing or implementing an initiative;

b. The costs of participation, including the level of operational and compliance costs on market participants; and

c. The level of administration costs on regulatory bodies.

4.2.2 Likely timeframe for implementation

284. A key aspect of any proposal is how quickly it can be implemented. Initiatives that require a short time period may be preferred over those likely to take a long time to show results. However, where projects involve risks, a slower implementation, possibly involving an initial trial phase, may be desirable to mitigate risks.

[13] Alternatively, productive efficiency occurs when maximum output can be produced for a given set of inputs. An improvement in productive efficiency increases welfare by freeing up resources for other uses.

4.2.3 Certainty that option will produce net economic gains

285. The final criterion is the degree of certainty that each initiative will deliver net economic benefits. Some of the initiatives are complex and involve large step changes for market participants, making it difficult to confidently establish their net benefits or net effects at this stage.

286. Two key considerations in quantifying the level of certainty are:

  a. the inaccuracy associated with the estimate of benefits; and

  b. the implementation risk of not achieving the projected estimate.

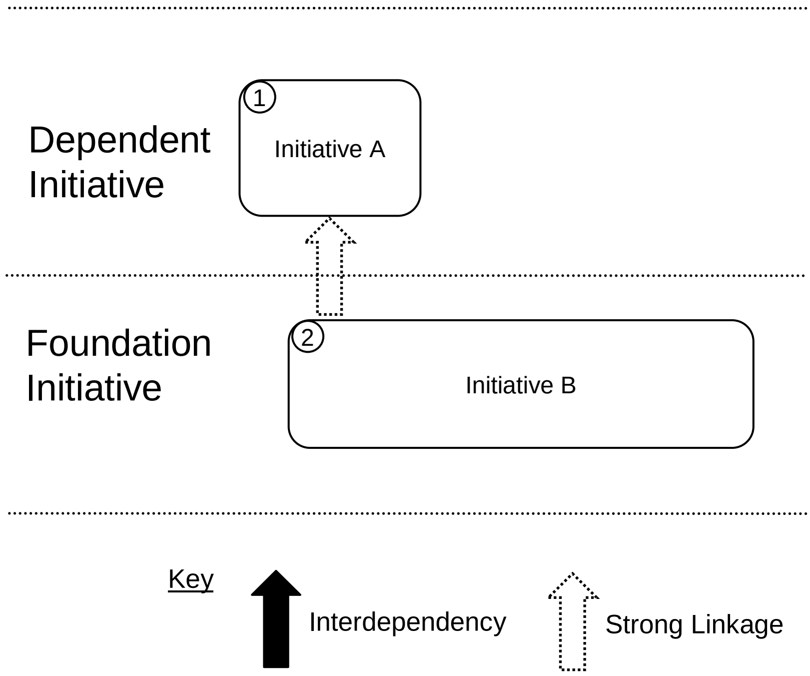
287. In general, it is lower risk to adopt an evolutionary approach rather than make radical changes for which the effects are highly uncertain.

4.2.4 Interdependencies and linkages

288. A key consideration for the Commission is linkages and interdependencies between initiatives.

289. Two initiatives are interdependent when one initiative materially affects options available with the other initiative. In the illustration below, the foundation initiatives can be implemented in isolation, whereas the dependent initiatives would benefit from the successful implementation of at least one another initiative. A black arrow indicates where there is an interdependency between two initiatives.

290. Linkages among the initiatives reflect the common set of effects the initiatives have on the efficiency of the risk management market and are aimed at identifying synergies. The dashed arrow indicates a strong linkage between two initiatives. If two initiatives exhibit interdependencies then a linkage is clearly present. The illustration will include a number next to each initiative that is a reference to the order in which the initiatives are listed. For example – the survey is the first initiative considered and will be numbered 1.



4.2.5 Relationship between evaluation criteria and overall evaluation

291. It is difficult to quantify costs and benefits in monetary terms for many of the initiatives that are evaluated in section 6 (Generic risk management initiatives) of this paper. For this reason, the overall evaluation of the initiatives in section 8 uses a comparative rating as a substitute for benefits and costs.

5 THE BASELINE MARKET

292. This section outlines the market as it is expected to develop without the policy initiatives discussed in this paper. This provides a consistent point of reference against which the market development options are assessed in later sections of this consultation document.

293. The baseline is not necessarily the status quo or optimal development path, but rather it is an assessment of how the physical and financial electricity markets would most likely develop without the initiatives presented in this paper. While we have endeavoured to depict as realistic a baseline as possible, it will inevitably be artificial to some extent as many scenarios are possible. The baseline, nevertheless, provides a consistent basis for comparing the costs and benefits of options.

294. There appear to be several developments occurring in response to the Commission's review of the risk management market, which makes it difficult to differentiate between developments that would occur anyway in the absence of the Commission's review, and those that are occurring in response to this work and would cease if this work ceased. The baseline described below does not seek to differentiate market developments on this basis, and includes both forms of development.

295. The timeframe for the baseline specification needs to cover the period over which the initiatives are likely to affect market outcomes. Under standard cost-benefit analysis, future costs and benefits of initiatives are discounted at a rate to reflect the time value of capital. Normally a five to eight year timeframe from the date initiatives are implemented is sufficient for assessing simple initiatives, particularly if they are not capital intensive.

5.1 Generic electricity risk management

296. Large market participants currently manage energy price risk using three main mechanisms: vertical integration, OTC contracting and through *EnergyHedge*. The assumptions made about the evolution or development of each of these mechanisms are listed below.

5.1.1 Vertical integration

297. We assume vertical integration of generation and retail will continue as the main form of managing energy risk for each of the existing vertically integrated wholesale market participants. A very high level of Government intervention would be required to reduce the level of vertical integration, and it seems highly unlikely this would occur in the near future. We also assume that bilateral OTC contracts will continue to be struck between these participants to offset some higher risk (generation/retail) imbalances, generation outages and dry year scenarios – particularly where regional constraints are likely to impact.

5.1.2 Over the counter (OTC) contracting

298. For consumers exposed to spot market prices, we anticipate that OTC contracts will be the only form of risk management instrument, apart from self-generation, available to cover general electricity price risks. Contracts are likely to be relatively limited at

nodes distant from the main generator nodes and key reference nodes (Benmore, Haywards and Otahuhu).

299. The baseline assumes contracting is likely to occur predominantly at primary nodes, leading to increased standardisation of contracts over time in respect of location. However, we assume force majeure (FM) and suspension clauses in contracts will remain, due to the specific physical characteristics of some generators' portfolios.

300. The major generator/retailers have, since the issue was discussed at HMDSG, begun developing a model master agreement for derivative contracts, which could be used for OTC and *EnergyHedge* derivatives. Although the idea of a model master agreement was first mooted at the time *EnergyHedge* was developed, discussions at the HMDSG have progressed participants' understanding of the issues and have motivated Major Electricity Users Group (MEUG) and the *EnergyHedge* participants to commit significant resources to developing a model master agreement.

301. Given the industry's early progress with preparing a model master agreement, it could be included in the baseline case or as an initiative of the HMDSG. We have adopted the former approach, and decided to specify the HMDSG initiative as one where the Commission monitors and possibly supports the model agreement.

302. The baseline assumes the model agreement will be completed to the satisfaction of the major generators and MEUG, and that those parties will progressively adopt the model agreement for OTC derivatives. It is envisaged that widespread adoption of this model agreement by the major generators would flow through to all market participants. The baseline assumes the lower negotiation costs brought about by the model agreement will increase participation slightly in the derivatives market.

303. For the vast majority of small end-users (less than 10 GWh/annum), we assume the primary contract will be of the 'fixed price-variable volume' type, representing a fully hedged position for the purchaser. These contracts are not tradable in a secondary market.

304. The baseline assumes OTC purchasers will be indirect users of *EnergyHedge* – that is, they will observe prices traded on *EnergyHedge* and expect to receive a base energy price closely related to *EnergyHedge* prices, and then negotiate margins to reflect their particular requirements and circumstances, in regard to volume, profile, location, credit risk, presence of FM and suspension clauses, and so on.

305. M-co's Fixed Price Contract Index is assumed to be the primary source of aggregated information on derivative prices negotiated through the OTC market.

5.1.3 EnergyHedge contracts trading

306. We assume there will be development of the *EnergyHedge* trading platform by its current participants such that additional approved parties may participate in derivatives trading through *EnergyHedge.*

307. The baseline assumes the requirement to post two-way prices will remain in place, and end-user purchasers will continue as indirect users of *EnergyHedge* – that is, they will observe prices traded on *EnergyHedge* and contract with the direct participants of *EnergyHedge* via the OTC market.

308. We assume that two-way pricing and counterparty credit risk considerations will limit the number of additional participants provided direct access to *EnergyHedge*. Banks, or any other organisation without a physical position, are unlikely to enter the

EnergyHedge market due to a number of commercial reasons, including their lack of physical position in the market.

309. The baseline assumes the model master agreement currently being developed by the major generators and MEUG will be completed to their satisfaction, and will be rapidly adopted for *EnergyHedge* trades.

310. Volumes traded on *EnergyHedge* are assumed to grow over time as a result of the introduction of multiple tranches and the model master agreement, but volumes are assumed to remain a very small fraction of volumes conducted through the OTC market. In the baseline market *EnergyHedge* is assumed to provide a transparent forward price curve out to 27 months but as it is not designed to clear large volumes we assume market liquidity will remain at its current level.

5.1.4 Other risk management activities

311. In addition to the risk management techniques outlined above, some participants also adopt other approaches to managing spot pricing risks. For example, one industrial participant currently views the money it earns in the reserves market as a key mechanism for mitigating risk in the energy market. The baseline assumes that participants will continue to adopt this strategy.

312. Some of the largest industrial consumers may be able to partially manage their energy risk through political influence. One example of this is the lobbying that contributed to the introduction of the reserve generation scheme following the hydro crisis of 2003.

313. Generators may also have alternative means of managing risk through political intervention. For the Genesis E3P generation project, the Government entered into a risk sharing agreement for supply of gas. There was a lack of consultation during the formation of this agreement and the industry questioned whether this deal favoured Genesis and distorted investment signals in the generation sector. The baseline assumes that this arrangement was a special case and unlikely to occur again in the future.

5.2 Managing locational price risk

314. The baseline assumes there will be no change to the transmission risk management tools available to market participants – that is, the only locational instruments available will be through OTC contracts that bundle energy and locational price risks. In these circumstances we assume there will be few occurrences of end-user purchasers receiving easily comparable offers from two or more generator/retailers. The baseline assumes there will be circumstances where purchasers believe generators exercised market power in their contract negotiations.

315. In conjunction with Transpower raising transmission revenue through an approved transmission pricing methodology, the baseline assumes the current method of allocating rentals to transmission customers will continue.

5.3 Underlying physical market

316. Market participation is likely to remain highly concentrated with no major additions to the generation or retail players. Decisions made by a single generator in relation to

the operation of generation plant have the potential to significantly affect market prices. This compares with other markets where the actions of an individual player may not impact on the market prices.

317. The assumptions in this section relate to work streams outside the direct scope of the hedge market work stream and the HMDSG. As such, the assumptions below do not mean the Commission is not intending to consider reforms to the underlying physical market, but rather that these assumptions provide the best foundation for the baseline. The implications of changing some of these assumptions are discussed in later sections of the paper.

318. The baseline assumes nodal pricing will be retained for generation dispatch and for wholesale spot market pricing, and the wholesale market will continue to be a gross pool. The baseline assumes changes proposed by the demand-side bidding and forecasting project (currently in-progress) will be implemented, providing improved forecasting of prices and the opportunity for more efficient use of demand side response.

319. The baseline assumes investment in transmission or transmission alternatives will occur over the next three to seven years to avoid power supply outages into the Christchurch and Auckland regions. These investments will significantly reduce the frequency and duration of binding grid security constraints along the main HVAC and HVDC network, and will significantly reduce locational price risk for many spot market purchasers for 10 – 20 years. Significant locational price risk may remain for purchasers in the Bay of Plenty, Hawkes Bay, and the West Coast of the South Island.

320. We also assume there are some participants that will continue to rely on the expectation of government intervention to manage spot price risk, as described in paragraph 312.

5.4 Competition in the baseline case

321. Although the UMR survey detailed participants' perception of the risk management market, it is not possible in this paper to determine, with reasonable accuracy, the competitiveness of the current risk management market. Contracts in the risk management market are highly differentiated and there is very little information available to outside observers. Rather than form views on the competitiveness of the risk management market, the policy initiatives discussed in the next section of the paper evaluates both the competitive and non-competitive scenarios.

322. As discussed in section 3.3.3, it is possible to take two starkly different views about the competitiveness of the *EnergyHedge* market. One view is that *EnergyHedge* participants offer highly competitive prices, as the contracts are highly standardised and are referenced to prices at a single node. The other view is that *EnergyHedge* provides a platform for generator/retailers to collude on prices as it is effectively a closed market and the volumes available on *EnergyHedge* are very small.

323. As with the OTC market, rather than form views on the competitiveness of *EnergyHedge* pricing, the initiatives discussed in the next section of the paper consider both scenarios.

6 GENERIC RISK MANAGEMENT INITIATIVES

324. The previous section outlined a baseline case for how the risk management market could develop over the next five to eight years. This section outlines the key generic risk management initiatives identified by the HMDSG and evaluates their likely net economic benefits to New Zealand.

325. Providing an effective mechanism for managing risks associated with nodal price differences is critical for further development of the risk management market and this is considered separately in section 7. Section 7 analyses two initiatives in detail for managing these risks, one focused on auctioning financial transmission rights and the other on allocating loss and constraint rentals to spot market purchasers most exposed to those risks.

326. Section 8 provides an overall evaluation of the initiatives, taking into account linkages and interdependencies among the initiatives, and identifies a preferred package of initiatives.

6.1 General approach

327. The generic risk management initiatives presented in this section are ordered according to the degree to which they are likely to influence the commercial operations of risk management market participants. In order of least intrusive to most intrusive, the key generic initiatives are as follows:

1. Regular survey of participants;
2. Publication of contract details;
3. Publication of outage and fuel information;
4. Model Master Agreement;
5. Development of EnergyHedge*;*
6. Understanding risk management;
7. Mandatory standardised contracts;
8. Exchange-based trading of mandatory contracts;
9. Synthetic separation of retail and generation;
10. Mandatory offering requirements on generators; and
11. Mandatory hedging requirements on purchasers.

328. The intention in this section is to provide rigorous and comprehensive analysis of the initiatives, looking at all of the possibilities in a considered way before presenting judgements about the costs and benefits that are likely to be significant. To achieve this, each section:

a. *identifies the key problems the initiative is believed to address.* This section is written from the perspective of promoting the initiative (Promoter's view), and includes a discussion of possible "market failures" that might be used to explain why voluntary action is unlikely to address those problems without the initiative;

b. *specifies the initiative in detail*, including how it could be implemented. This approach is adopted to better understand the practicalities of implementing the initiative and how it might affect the behaviour and choices of market participants;

c. *evaluates potential benefits, costs and risks of the initiative*, relative to the baseline assumptions about the risk management market; and

d. *draws conclusions about the overall net economic benefits of the initiative,* including implementation timeframe and the certainty the initiative will produce net economic benefits or costs.

329. A large number of possible initiatives were identified by the HMDSG in its investigations over the last 18 months. Appendix B contains the full list of the generic risk management initiatives considered by the HMDSG, and provides an outline and high-level evaluation of each initiative, including a rationale for why or why not an initiative was considered suitable for further specification and analysis.

330. The HMDSG also considered ways in which the wholesale physical market could be changed to facilitate a more efficient risk management market. Appendix D identifies some options and the affect these options may have on the risk management market.

6.2 Regular Survey initiative

Overview

This initiative proposes the Commission oversees and funds a regular risk management survey. The initiative is directed at improving information about the performance of the risk management market, to enhance confidence in the market and, where that is not achieved, identify areas requiring further consideration.

The initiative is likely to produce net economic benefits for New Zealand, as the quantitative and time series aspects of the information available from the survey is likely to be useful for making future risk management policy decisions. This should improve market performance over the longer term. The initiative is low cost and low risk, as surveys can easily be discontinued if the net economic benefits of conducting them become negative.

6.2.1 Introduction

331. The survey initiative involves the Commission funding and overseeing a regular survey of market participants, using a similar questionnaire to that used in the UMR survey undertaken in mid 2005.

332. The survey would be voluntary for participants, but would be expected to cover all spot market participants and a selection of large, medium and small end-users that contract for electricity supply from spot market participants.

333. The questions asked in the surveys would be similar to the 2005 survey, and would be designed to track changes in respondents' views over time to detect whether or not their perceptions and trading levels have changed over time. Survey responses would remain confidential to the surveying company.

6.2.2 Promoter's view

Key problems

334. As discussed in section 3.3.1, current arrangements provide market participants and policy makers with very little robust information about many aspects of electricity risk management practices, making it difficult to assess the performance of that market. This lack of information is also believed to be contributing to a lack of confidence, among many market participants, in the competitiveness of the risk management market, as discussed in section - 3.3.3.

335. Promoters of the initiative believe a regular survey will help address these problems by providing the Commission, and market participants, with valuable information about trends in the perceived performance of the market, which they can draw on when considering future risk management market initiatives. The initiative is expected to be beneficial even if the initiative in the next section of this paper – publication of contract details – were implemented, as this latter initiative does not provide information about the confidence market participants have in the risk management market.

Possible economic rationale

336. For the surveys to have the required credibility, they need to be directly financed and managed by an independent party, and undertaken by an independent survey firm. Survey information voluntarily collected by market participants, or groups of participants, will not have the same level of credibility, as there would inevitably be an implied bias from the vested interest of the financier.

337. As the Commission is an independent body and the primary user of the survey results, it should fund and oversee the regular survey. The survey would be conducted by a professional research firm who would be the only organisation that has access to the raw survey data. The high response rate to the 2005 UMR survey indicates respondents have confidence the Commission will maintain the confidentiality of their summarised responses. The Commission also has a leadership role in encouraging participation in policy debates on the risk management market, and therefore should use the survey to improve understanding of current market outcomes and sentiments.

6.2.3 Specification of the initiative

The parties surveyed

338. The regular survey of risk management market participants will cover:

a. all participants who are exposed to the wholesale spot electricity market; and

b. a selection of large, medium and small end-users that contract for electricity supply from spot market participants.

339. The 53 organisations surveyed in 2005 would provide the core of future surveys. It is expected that some respondents may not wish to participate in consecutive years, or more than once, and an appropriate level of refresh would be incorporated into the sample of end users that contract with retailers. With this refresh proposal it is expected that organisations will be willing to participate in the survey and it will remain a voluntary arrangement. The Commission may consider making the survey mandatory if the list of voluntary respondents is not representative of the market.

The information sought

340. The questions asked in the surveys would be similar to the 2005 survey. The questions would be designed to enable tracking of changes over time to detect whether or not participants’ perceptions of the risk management market have improved over time, with or without market reforms.

341. In 2005, UMR was commissioned by the Electricity Commission to conduct research to provide information that would assist it to determine:

a. whether or not there is a shortage of CfDs in the market;

b. what constitutes an effective CfD from a buyer’s perspective, particularly the relationship between price, basis risk and force majored;

c. whether generators have the ability to exercise market power in either the wholesale spot market or the risk management market and, if so, the extent of that power and its implications for the derivatives market;

d. whether vertical integration adversely affects competition in the retail market, the market for derivatives and investment in new generation;

e. whether vertical integration is the most efficient market structure given the physical and commercial drivers underlying the New Zealand electricity market; and

f. whether issues relating to the lodgment of CfDs for prudential security are significant.

342. It should be noted that the research was not designed to provide answers to those questions, but to gather empirical information and perceptions related to the issues they raise to assist the Commission's determinations which will draw from this and a variety of other sources.

343. The report from the survey will include a CfD seller performance rating derived from an aggregation of the views of the purchasers.

The survey methodology

344. The surveys will use both a written questionnaire and a face-to-face interview to collect the views of each respondent. The written questionnaires will be issued first and followed up with (selective) interviews to verify the written responses and to facilitate accurate interpretation for aggregate reporting of findings.

345. All the generators, retailers and end-user participants in the spot market will be interviewed, plus a selection of the end-users that contract with spot market participants. Survey responses will remain confidential to the surveying company.

The surveying parties

346. The Commission is the principal surveying party, and will engage a suitably qualified independent market research organisation to conduct the interviewing, analysis and aggregation for publication. The Commission's main interest in who actually performs the surveys will be consistency of questioning and interpretation of responses. That is, quality assurance, independence and confidentiality will be the prime drivers of who is appointed to conduct the surveys.

6.2.4 Potential benefits

Better informed policy-making

347. Relative to the baseline case, 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 what, if any, further policy initiatives are required to improve the performance of the risk management market.

348. Policy-makers will of course draw on information provided by other sources, such as from ongoing representations made by current and potential market participants and from submissions made to future consultation documents, but a regular survey adds a more representative and uniform dimension to information about the performance of the market. In our view, the quantitative and time series aspects of the information available from the surveys will provide useful information for policy-makers, and will be influential in making future policy choices.

349. Conducting surveys of the type undertaken in 2005 should support the Commission in making good policy choices. For example, the Commission is likely to consider rather different options if the surveys showed increasing comfort or satisfaction with the performance of the risk management market than if the surveys produced static or

increasingly negative results. Without the proposed initiative, the Commission is more likely to either introduce further reforms when they are not needed or fail to introduce reforms when they are needed.

350. It is difficult to accurately quantify the benefits of better-informed policy-making, as it involves postulating the Commission's decision-making now without surveys, and postulating how this might improve over time. Nevertheless, better policy decisions in this area have the potential to create large efficiency gains for the economy because they would affect the commercial operations of most spot market participants, who in turn represent a large portion of the economy.

351. The prospect of better-informed policy-making should reduce regulatory risk for all market participants, as regulatory decision-making should be more predictable and rational. This should create economic benefits across-the-board, as more efficient investment occurs in response to lower risk premiums for investors.

Other benefits

352. Disclosure of 'CfD seller performance' ratings from the survey information has the potential to stimulate innovation.

353. It is also possible the regular survey may stimulate more efficient risk management decisions, by generating greater knowledge about the risk management market, and perhaps greater confidence in the derivatives market in particular.

6.2.5 Costs and risks

Administration and compliance costs

354. Implementing the initiative is straight-forward, as it is just a matter of repeating the 2005 survey. Nevertheless, regular surveys would impose direct costs on market participants, as they would need to complete the surveys and participate in 'depth interviews' with the survey firm. The Commission would also incur costs to manage the survey firm and pay for it to conduct the surveys.

'Block voting' risks

355. There is increased potential over time for respondents to collude in their responses to questions concerning the performance of the risk management market, in favour of a risk management framework preferred by that group of participants. The publication of the 2005 results could, for example, prompt a degree of discussion between parties with similar interests to ensure that in advance of the next survey there is unanimity in their views on the extent to which the risk management market is competitive, or the reasons why it may or may not be competitive.

356. The more surveys conducted, the higher the likelihood of this type of behaviour. Our view is there is some risk of 'block voting' behaviour, but this should not be over-estimated. If the Commission becomes concerned about 'block voting' it can cease conducting future surveys, or it can discount the results if 'block voting' is a serious issue. In net benefit terms, 'block voting' risks appear to be too small to include in the cost-benefit analysis.

Gaming risks

357. It appears reasonable to assume all survey participants are capable of identifying when others are 'gaming the survey' by altering their behaviour in the derivatives

market close to the time when the survey is conducted. This would be particularly noticeable in regard to factors important to their business, such as the availability of derivative offers, and particularly if the gaming behaviour is repeated regularly.

358. On this basis we assume gaming behaviour will be minimal and respondents will complete their survey forms as accurately as they have for the 2005 survey. We therefore conclude the costs of possible gaming behaviour are too small and too uncertain to include in the net benefit assessment.

Low response risks

359. There is also a risk the regular surveys will attract decreasing participation by end users and others, especially if they do not observe improved hedge market performance or their favoured policy initiatives. As with ‘block voting’ risks, the Commission can cease conducting future surveys or reduce the frequency if response rates are low.

6.2.6 Conclusions

Timeframe for implementation

360. 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 four months.

Certainty of net economic benefits

361. The survey initiative is a simple initiative. The main risk is that participants get tired of, or annoyed with being surveyed, and there is also a risk that ‘block voting’ and gaming may occur. To some extent the ‘block voting’ and ‘gaming risks outlined above can be managed through good questionnaire design and implementation.

362. However, the Commission is not stuck with incurring costs for no benefit as it can cease conducting surveys if the net benefits of the survey are negative. Alternatively, the Commission could alter its interpretation of the results or alter the survey in ways to protect against such behaviour. A significant portion of the Commission’s survey analysis will focus on market trends, rather than absolute measures, which will counter some of the risks outlined above. The policy and fiscal risks associated with this initiative are therefore minimal.

Overall Conclusion

363. Regular surveys of market participants has the potential to result in more informed policy making, which over time should produce a better performing risk management market and reduce regulatory risks. Given the paucity of information currently available on the risk management market, these benefits are highly likely to exceed survey costs.

6.3 Publication of contract details

Overview

This initiative requires market participants to publish key details of their risk management contracts, and is intended to facilitate ready comparability of prices and other key risk management terms. This initiative is primarily directed at addressing the lack of information available for parties to formulate their own forward price curves, and should provide a more informed basis for parties to assess the competitiveness of the risk management market.

The initiative is likely to produce net economic benefits for New Zealand. If the concerns about lack of competitiveness reflect reality, then publishing contract details should assist purchasers to more easily identify competitive offers, which would place greater competitive pressure on contract sellers. If, however, the concerns about competition are misperceived, and do not reflect reality, then publishing contract details should dispel those misperceptions and increase confidence in the competitiveness of the risk management market. In either case, the efficiency gains are likely to be relatively large.

Perhaps more importantly, publishing contract details should facilitate more efficient risk management decision-making by improving the accuracy and timeliness of forward price curves, facilitating more efficient use of brokers, and may encourage greater use of standardised derivatives, which in turn facilitate lower transaction costs and more efficient levels of market trading and liquidity.

The initiative is low cost, requiring minimal IT development expenditure and minimal ongoing administration and compliance costs. The main risk is in regard to the disclosed information facilitating collusive behaviour among market participants. This risk is considered negligible, as the competition regulators will also have more information with which to monitor participant behaviour.

6.3.1 Introduction

364. This initiative requires parties who enter into risk management contracts exceeding 10GWh / annum to publish details of their agreements. The details would cover the contract quantities, prices, reference nodes, duration, start and end dates, and other key terms and conditions. Contract counterparties would not be required to be identified. However, given the specialised nature of risk management contracts, it is possible that, given information on reference nodes and quantities, some contracting parties may be able to be identified.

365. Contract sellers would have the obligation to post their contract details on a website specified by the Commission, and purchasers would have an opportunity to dispute the accuracy of the details. All undisputed contracts would be automatically published on the webpage within a specified time period.

366. This initiative would require the Commission to implement rules specifying the details to be disclosed, when they have to be disclosed, who is required to disclose those details, where the details are to be published, and processes for monitoring and enforcing compliance with these requirements.

6.3.2 Promoter's view

Key problems

367. Key problems identified in sections 3.3.1 and 3.3.3 was the lack of robust information on OTC transactions, making it difficult for parties to establish their own forward price curves and feeding concerns about a lack of competitiveness of the risk management market. Promoters of the initiative believe mandatory publication of key contract details will address these problems, and that the initiative is critical for developing the risk management market, for the kinds of reasons discussed in section 3.2.4.

Possible economic rationale

368. The economic rationale for regulating the publication of contract details rests on the view that individual contracting parties have strong commercial incentives to keep private the details of their own contracts, but they all benefit from access to robust information about forward prices in the market. This is unlikely to occur in New Zealand without a regulatory requirement to publish the key details of most risk management contracts. Mandatory publication of contract details seeks to overcome this divergence between private and public interests.

6.3.3 Specification of the initiative

369. In order to ensure parties provide comprehensive and comparable information, the rules would specify the details to be disclosed, when they have to be disclosed, who is required to disclose those details, where the details are to be published, and processes for monitoring and enforcing compliance with the information disclosure components of the rules.

Discussion of high-level options

370. OTC contracts differ on many dimensions, not all of which would be easy to summarise accurately. One option would be to simply require contracting parties to publish their full contract details, and leave it to interested parties to summarise the information themselves. Brokers, for example, may find it commercially beneficial to prepare summaries and make them available to their clients if brokers become involved in the OTC market and if transaction volumes are sufficient to defray the cost of preparing the summaries.

371. A problem with full disclosure of contract details is that it would reveal commercially sensitive information about the counterparties, such as their risk management strategy and any potential proprietary knowledge about innovative structures. FM and suspension clauses can also often be commercially sensitive because they reflect the risks and vulnerabilities of the counterparties. In some cases revealing the reference node in the contract would reveal the identity of the counterparty, which risks other parties being able to monitor its risk management strategies.

372. Although these factors can sometimes be important for determining derivative contract prices, they are not present in all contracts and their effects on derivative contract prices are not always significant. Requiring full contract disclosure is likely to meet with considerable resistance by purchasers and generators alike, and does not appear to be necessary to gain most of the benefits of disclosure. Even under limited disclosure, there is a risk that well informed observers can deduce information about the identity of the parties to a transaction.

373. These considerations suggest the best approach is to require publication of key details of each derivative contract and large fixed-price variable-volume contract. To maximise the information content, the summary should provide as much disaggregated information as possible whilst avoiding unnecessary intrusion into the commercial affairs of counterparties.

The details to be disclosed

374. The following contract details would be required to be published for each contract:

a. Contract type, such as base-load CfD, base-load option, customised profile, fixed-price variable-quantity contract;

b. Quantity in MWh and/or MW, as appropriate (average MWs);

c. Key reference point, which may be a node or zone or hub at which price and quantity apply;

d. Start and end dates (quarters);

e. Trade date (quarters);

f. Prices and other fees;

g. Whether it has any indexation mechanism, and whether it has any arrangement to pass-through certain costs (like a carbon tax); and

h. Whether it includes any FM, suspension and special credit clauses.

375. Publication of contract terms would be mandatory for all contracts between parties whose gross consumption is above a specified level (10GWh/annum), whether obtained directly from generators, brokers, a futures exchange or any trading platform.

376. Contract counterparties would not be required to be identified, as doing so could create artificial incentives for parties to use contracting agents. For similar reasons, contracts might be referenced to pricing hubs or zones as a means of protecting the identity of counterparties, which would be more obvious if details were disclosed at the nodal level.

377. Figure 14 illustrates the form of the mandatory publication requirements discussed above. It is intended only as an illustration of the level of detail likely to be required by the initiative, and should not be taken as the proposed final form of the requirement.

Figure 14: Example of how contract details would 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

Who, how, and when contract details are published

378. Sellers of derivatives would have the obligation to publish their contract details on a website (or page on a trading platform website) specified by the Commission. Sellers would be required to meet this obligation within 15 minutes after the contract is struck, and purchasers would have the option to dispute the accuracy of the details within 60 minutes after they are published on the website. Sellers would incur fines for publication of incorrect trade information or for delaying beyond the 15 minutes.

379. The timeliness of this information, as specified above, is a crucial part of the benefits of the contract details requirements because it presents an opportunity for parties to signal that they would be willing to transact at the published terms or provide a superior deal. Timeliness is essential for this dynamic to develop.

380. In the event that standard contract trades were struck through an electronic trading platform, that platform would have the functionality to immediately publish the contract details and include the data on the specified website. The trade details are copied from the electronic trading platform to the website to ensure that all trade information is centralised.

381. A forward price curve will not be provided directly to market participants, just the information necessary to create it, because critical decisions regarding the impact of contract terms on price need to be made by each organisation rather than centrally.

6.3.4 Potential benefits

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

Direct benefits

383. The following benefits arise from the publishing of key contract details irrespective of any effect the initiative has on market power issues.

More efficient forward price curves

384. Publishing contract details will provide risk management market participants, including third parties such as brokers, with ready access to timely information for formulating forward price curves. If forward price curves become more accurate and timely than in the baseline case, then risk management market participants will be able to compare prices more efficiently, and formulate their own risk management strategies more efficiently.

More efficient brokering activity

385. The much greater information available on risk management market activity may spur greater brokering activity, as brokers will be able to use the information to prepare forward price curves and sell that information to consumers, along with general monitoring and contract negotiation services. This is a small risk that brokers may be used less as their inside knowledge of market activity will now be less valuable to their clients.

386. Whichever way it goes, brokering activity will be more efficient because it will be less about privileged inside knowledge and more about reducing transaction costs through specialisation of contracting activity.

More efficient use of standardised derivatives

387. Greater transparency regarding derivatives may ‘set in train’ a series of market developments that achieve more efficient use of standardised derivatives. For example, greater transparency may stimulate greater demand for comparability across contracts, which in turn may stimulate more efficient contract structures – for example, energy risks might be unbundled from location risks, and base load requirements might be unbundled from peak load requirements. The end result would be more efficient participation in standardised derivatives markets.

388. In addition, parties might have greater confidence in the market and be more willing to participate in it. This could result in parties being more willing to move away from FPVV contracts onto derivative contracts, and thereby increasing the liquidity of the derivatives market. Greater liquidity will give parties greater confidence around trading and result in more efficient managing of contract positions.

Cost savings

389. Publishing contract details is likely to remove retailer interest in publishing the Fixed Price Contract Index. This would bring savings in reduced administration of the Index and reduced compliance costs for generators.

Indirect benefits

390. Determining the indirect benefits of this initiative is complicated by:

a. uncertainty regarding the baseline – as outlined in section 5.4, it is not clear concerns about perception of market power and potential collusion reflect reality; and

b. uncertainty regarding the effects of the initiative – it is not clear whether publishing contract details would reduce unilateral market power (if it exists) or facilitate collusive behaviour (if it doesn’t already exist).

391. The following analysis proceeds first on the basis that concerns about market power reflect perception rather than reality (case 1), and then considers benefits that arise if

perceptions about market power are correct (case 2). This ordering is not meant to imply any additional credence to perception over reality, but is adopted because it allows for a clearer discussion of the issues.

Case 1: concerns about market power are misperceived

392. On the basis that concerns about market power are misperceived, then publishing contract details would dispel some of those misperceptions and increase confidence in the competitiveness of the risk management market. This should lead to more efficient participation in the risk management market generally, and in the derivatives market in particular, because energy users will be more confident they are getting a fair deal. This should stimulate more efficient levels of depth and liquidity in both markets.

393. Greater confidence in the competitiveness of the risk management market may also reduce implicit barriers to entry in the retail market, potentially spurring more competitive retail market outcomes in areas where contracts cover both the risk management market and the spot market.

Case 2: concerns about market power reflect reality

394. Alternatively, end user concerns about market power may reflect reality, in regard to unilateral market power in the OTC market or collusion through the *EnergyHedge* trading platform which is then leveraged into the OTC market and/or the spot market. If generators exercise market power in the risk management market, then we assume this would be leveraged into the retail market and other elements of the wholesale market.

395. As discussed above, publishing contract details may lead to more timely and accurate forward price curves than the baseline case. If this occurs, greater competitive pressure on generators would arise because the price of differentiated contracts could be easily compared. This would facilitate more efficient risk management decisions by purchasers.

396. Publishing contract details may also make it easier for purchasers and regulators to analyse risk market information to detect any instances of generators unilaterally exercising market power. Under current arrangements it is virtually impossible to empirically investigate and assess market power in the risk management market, as few contract prices or other details are available.

397. Increasing the quantity of detailed information available to regulators will increase the probability that illegal exercise of market power will be detected, in the event that it ever arises. This, in turn, is likely to encourage any generators and related parties with market power to avoid making offers that constitute (or give the impression of constituting) an exercise of market power.

398. These considerations suggest that if some generators exercised unilateral market power under current risk market arrangements, their ability to do so would likely be substantially eroded by this initiative, and would flow through to more competitive pricing in the physical market. This could occur because generators without contracts would be more likely to compete at the margin in order to ensure they were dispatched.

399. Section 5.4 postulated that generator/retailers could be using *EnergyHedge* to tacitly collude in setting OTC prices. If this is the case then, at worst, publishing the details of OTC contracts is unlikely to exacerbate collusion because regulators would gain

much more information about OTC prices than generators (who are 'insiders' and so already know some of the trades). The increase in regulatory threat against tacit collusion should exceed the gains generator/retailers make from being able to better observe their competitors' actual pricing in the OTC market. Hence, if collusion already exists, the initiative is unlikely to exacerbate it.

Better informed policy-making

400. As alluded to above, publishing the details of OTC CfDs provides more information to competition regulators, which should result in better-informed competition decisions. Also, competition interventions should be more predictable, reducing regulatory risk for all market participants. As for the previous initiative, this should create economic benefits across-the-board, as more efficient investment occurs in response to lower risk premiums for investors.

401. Similar effects arise from the effect the initiative has on purchasers' concerns about market power. By dispelling those misperceptions (if that is what they are), the initiative reduces the risk of inefficient regulatory interventions in the risk management and spot markets because it reduces external pressure on regulators to impose interventions.

Reconciling perceptions versus reality

402. It is not necessary to justify the benefits of the initiative on claims that market power and collusion are real, provided the benefits of correcting misperceptions (if that is what they are) exceed the costs of the initiative. If perceptions of market power are correct, then this initiative will erode their influence over time.

403. For the purposes of the net benefit assessment in this paper, we assume concerns about market power are misperceived (case 1 above). Under this scenario, the benefits of the initiative occur in the form of greater confidence in the risk management market, leading to more efficient levels of participation and liquidity.

6.3.5 Costs and risks

404. The initiative imposes direct costs on market participants, in the form of compliance and administration costs, and has some potential to impose indirect costs on consumers and market participants by altering the behaviour of contracting parties.

Administration and compliance costs

405. Implementing the initiative should be straight-forward in practical terms. Some IT development expenditure would be required to establish a web page with registration and log-on facilities, standard forms, and automatic email notification between sellers and buyers.

406. Implementing the initiative would require one-off costs associated with developing the information disclosure rules, and further costs related to refining them over time as experience is gained with them.

407. The initiative would also impose regular ongoing costs imposed on buyers and sellers of contracts to comply with the information disclosure rules, and ongoing administrative costs for the Commission in regard to paying for auditors and enforcing the new rules via the Rulings Panel.

Collusion risks

408. The benefits subsection considered the effects of the initiative on collusive behaviour if it already exists in the base line case. The alternative scenario is there is no collusion in the baseline case because it is difficult for generators to observe OTC prices. Under this scenario, publication of contract details could increase the potential for collusion by providing information for generator-retailers to observe their competitor's pricing in the OTC market.

409. The assessment in this paper is that these risks are minimal because generators will not know the counterparties to the pricing information, and so will have limited ability to punish competitors. Regulators will also obtain greater information on OTC prices, and so will be better placed to monitor and take action against collusive behaviour.

Disinformation risks

410. With a requirement to publish contract details, there is a risk of related parties (or colluding parties) striking dummy contracts with prices, quantities and other terms set specifically for the purpose of creating incorrect forward price expectations in the market. However, this type of collusion is unlikely to occur, as it is illegal under the Fair Trading Act 1986.

Enforcement risks

411. An important risk with the initiative is that some participants may seek to contract in a way that distorts the published information, making price disclosure ineffective as a means of enhancing market transparency.

412. Another risk is that some parties might strike contracts and agree not to disclose the presence of those contracts, breaching the rules. This is very unlikely as it would require two parties to agree to withhold. Although purchasers may want disclosure to gain access to information about other parties' contracts without having to disclose their own contracts, it is unlikely that generators would be willing to risk any sanctions or reputational risk. In addition, participants will be relying on the dataset to formulate robust forward price curves and will want to ensure that others are complying fully – if one party was found to not be complying, the resulting suspicion of other parties undermines the value of the information.

413. Furthermore, although it would be difficult for any third party, such as an auditor, to identify missing contracts it is unlikely that large participants would purposely breach the rules and risk the reputational consequences of doing so.

414. All these risks are considered to be minimal, as such behaviour is illegal and readily detectable in the close-knit New Zealand environment.

Other costs and risks

415. As this initiative requires introducing new rules, there is a risk of 'regulatory creep' occurring where additional rules and additional layers of complexity are added to the initiative over time. This would result in additional costs, and reduce market evolution and innovation.

Risk of unsuccessful implementation

416. Although the technical implementation of this initiative is relatively simple the publication of contract details is a fundamental shift for market participants.

417. The Act provides for the Minister of Energy (Minister) to make regulations in regard to the disclosure of information on hedge contract volumes and prices. The greatest implementation challenge for this initiative will centre on the policy specification phase. There is a risk that the intended market benefits will become diluted as compromises are made during the consultation process.

418. There is a risk that independent parties do not see a commercial opportunity from turning the raw contract information into a meaningful and robust FPC. Without this independent support the initiative will deliver less benefit to the market participants that do not have the resources to generate their own FPC.

6.3.6 Conclusions

Timeframe for implementation

419. If the Commission decided to adopt this initiative, it would need to formulate rules specifying the contract details that sellers would be required to disclose to the market and how these would be published. The rules would probably take 6 - 12 months to prepare and another 3 – 6 months to consult on and provide recommendations to the Minister. The development of the appropriate technical infrastructure would take approximately 6 months. The initiative could therefore be implemented within a 1 – 2 year timeframe.

Certainty of net economic benefits

420. Although there are some risks parties may undertake trades to distort average price levels, or alternatively not report trades, both risks are likely to be minor. A more significant qualification to the net benefit assessment is the judgement that the initiative will significantly enhance participation and liquidity in the risk management market.

421. Publication of contract details is however a simple intervention to implement, and simple for participants to comply with. With very little information currently available on the contracts market, it is highly likely to produce significant net economic benefits.

Overall conclusion

422. The benefits assessment in this paper is based on the presumption that concerns about market power are misperceived. In this situation, publishing contract details would dispel those misperceptions and increase confidence in the competitiveness of the risk management market. This should produce more efficient levels of participation and liquidity in the risk management market, and should result in better-informed competition policy decisions.

423. There are also other, more direct, benefits from publishing contract details, such as more efficient risk management decision-making arising from:

a. A greater accuracy and timeliness of forward price curves;

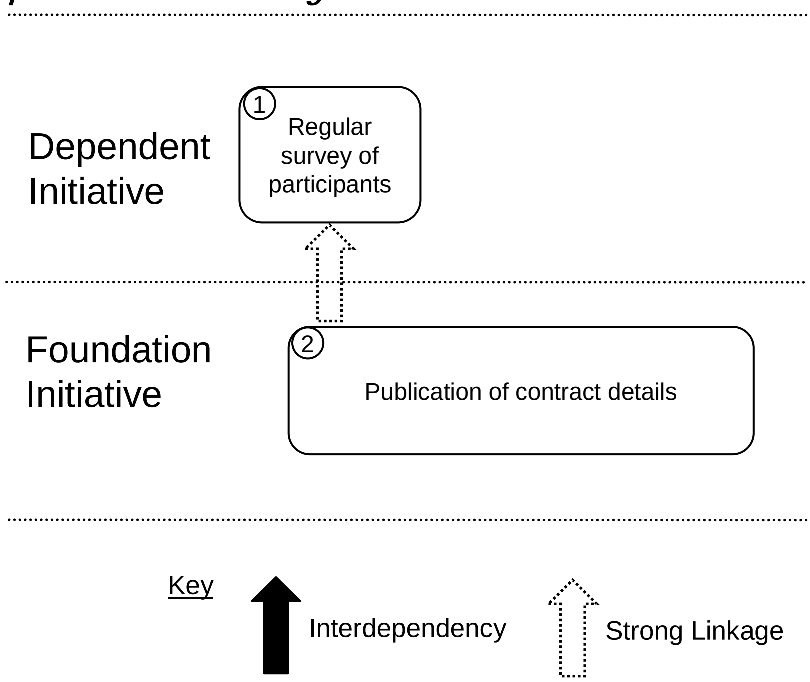
b. More efficient use of brokers; and

c. A greater use of standardised derivatives, which in turn facilitate lower transaction costs and more efficient levels of market trading and liquidity.

424. Overall, it would appear the initiative is low cost, requiring minimal IT development expenditure and minimal ongoing administration and compliance costs. The main risk is in regard to the disclosed information facilitating collusive behaviour among market

participants. This risk is considered negligible, as the competition regulators will also have more information with which to monitor participant behaviour.

Interdependencies and linkages



425. The publication of contract details is likely to provide market participants with the information they require to make an informed comment in the regular survey regarding the state of the risk management market. Without the publication of contract details the regular survey would only gather the perception of market participants who have little knowledge of what is occurring in the broader OTC market.

426. The publication of contract details is independent of the regular survey – that is, the publication of contract details initiatives should be undertaken regardless of whether the regular survey is completed.

6.4 Centralised publication of outage & fuel information

Overview

This initiative involves the Commission centralising outage information, for load, generation and transmission, and fuel information onto a readily accessible and standardised web platform, and converting the information into GigaWatt-hours so that it is meaningful to risk management market participants.

This initiative is primarily directed at reducing any barriers to participating in the risk management market, and providing essential information relevant to the sale and purchase of risk management instruments. The initiative should make it easier for smaller participants to formulate more accurate views about forward prices, and to better understand the risk assessments made by generator/retailers. Both factors should assist with addressing lack of confidence in the competitiveness of the market.

Centralising and converting outage and fuel information is likely to produce net economic benefits for New Zealand. It should lead to more efficient pricing of risk management products by end-users, and stimulate more efficient levels of trading and liquidity in the derivatives market. The initiative involves minimal IT development and administration costs, and some additional compliance costs on information suppliers. There are minor risks that information suppliers may adopt a more conservative approach to the provision of information, depending on whether penalties are imposed on them for supplying inaccurate information.

6.4.1 Introduction

427. The initiative involves the Commission relocating and centralising outage and fuel information onto a platform that is more readily accessible and standardised than the current platforms used to provide such information. In addition to accessibility, the Commission should attempt to make the information more timely, accurate and meaningful to risk management market participants. For example, all fuel information should include a GWh conversion so parties are not required to perform complex calculations.

428. Transpower and market participants would be requested to provide timely and accurate data on planned generation, load and transmission outages, fuel stocks and fuel prices. Rules might be considered for specifying how and when price sensitive information should be disclosed, or perhaps a more general information disclosure and insider trading rule might be considered instead.

6.4.2 Promoter's view

Key problems

429. As section 3.3.1 discussed, one of the key problems inhibiting efficient risk management appears to be the lack of low-cost, accurate, and meaningful information on fuel and plant outages. The promoters of this initiative believe it will address these problems by relocating and centralising outage and fuel information, and adopting a format that is easy for risk management market participants to use. Including information about planned load outages from large consumers will also be important where such outages affect spot prices.

Possible economic rationale

430. In general, market participants can organise their own information sources. This will be efficient for participants using private sources of information, as they will trade off the costs of obtaining and organising the information against the value they derive from additional information.

431. In most industries, planned outage and fuel supply information would be considered private to the organisations involved. However, in the electricity industry individual generation plants and fuel supplies are often significant in terms of influencing spot prices and derivative prices. Likewise, transmission and large load outages often affect spot prices and derivative prices. These considerations render outage and fuel supply information of significant public value.

432. The economic rationale for this initiative rests on the view that planned outage and fuel supply information carries significant public value, and needs to be readily available and easily accessible to risk management market participants at low cost. Although short-term coordination is managed by the system operator, efficient longer-term coordination rests on participants acting in their own interests given the information they have about future electricity supply and load levels. Simple and low-cost access to accurate information about fuel supplies and planned outages would assist participants in making efficient investment and risk management decisions, and may also improve medium to long term system security .

6.4.3 Specification of the initiative

433. The initiative entails the centralisation of outage and fuel information onto a platform that is more readily accessible than is currently the case. The work required is an improvement to existing processes rather than developing new systems.

Information to be published

434. The information to be published will include:

a. current and historic hydro storage levels and inflows;

b. planned generation, transmission and large load outages, and impact on expected supply capability over the period of outage, by region as applicable;

c. medium or long-term gas and coal availability and prices, where readily available; and

d. current and historic wholesale coal, oil and gas prices, from both spot and forward markets, where readily available.

The who, how and when of publishing the information

435. Transpower, generators and large consumers would be requested to provide timely and accurate data on planned outages, fuel stocks and fuel prices.

436. The specific nature of the information disclosure rules, if any, has not been specified for this initiative. There appear to be three broad options for the rules for governing the supply of the information:

a. No rules on information providers – this would be similar to the current reasonable endeavours arrangements but the information would be collated centrally and converted into GWh;

b. A generic insider trading rule – parties would be required to disclose all information that might materially affect the spot price of electricity; and

c. Specific rules – the Commission could expand on the insider trading rule to specify how and when price sensitive information should be disclosed.

437. The current party who is responsible for delivery of this information, the system operator, would be invited to develop their system to collate and publish the information. The information would need to be updated each business day for outage and hydro information, and weekly (or monthly, if more appropriate) for gas and coal information. The information would be presented in an easily understandable format for risk management market participants and in a readily accessible location, such as a web site. In the event of there being a website for the publication of contract details, the information would likely be housed on that facility, which would be independent of the Commission.

Monitoring

438. To ensure the new arrangements meet the needs of risk management market participants, 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, providing information on the volume of website hits, percentage of uptime, and percentage of helpdesk calls resolved within defined time periods.

Implementation issues

439. The Commission or the contracted agency would need to develop standard data transfer protocols, conversion algorithms, data upload and download functionality, and compliance testing requirements. Issues around collection, collation, and publication of hydrology datasets would also need to be worked through with M-co, NIWA, and dataset subscribers.

6.4.4 Potential Benefits

440. The potential benefits of the initiative arise from the effect it has on parties' risk management decisions, in regard to:

a. the way they determine prices for electricity derivates; and

b. their participation in the derivatives market.

More efficient pricing for electricity derivatives

441. One of the potential benefits of the initiative is that it may improve end-users' derivatives purchasing decisions through assisting them in forming more accurate views about likely future electricity prices. In contrast to end-users, generator/retailers utilise trading teams that spend time gathering and synthesising information available from a wide range of sources. Reducing these asymmetries is likely to assist end-users to negotiate more efficient derivatives prices in the OTC market, and potentially encourage them to cover a larger portion of their exposures with derivatives.

More efficient use of the derivatives market

442. The initiative may also result in more efficient use of derivatives to manage price risks, rather than FPVV contracts. With more up-to-date knowledge of planned outages and future fuel supplies, purchasers are likely to be more confident buying derivatives and trading their position as fuel and outage information changes. This

could increase the depth of the derivatives market, and contribute to a self perpetuating effect on liquidity and further market depth.

443. Another possibility is that better information available to purchasers assists them to better understand fuel shortages facing generators, and make more informed judgements with respect to generator market power. The better understanding would improve confidence, and encourage greater purchaser participation in the derivatives market.

6.4.5 Costs and risks

444. The costs and risks of the initiative relate primarily to administration and compliance costs, development costs, and to the effect on the supply of information.

Development costs

445. As with publication of contract details, implementing this initiative should be straight-forward in practical terms. Some IT development expenditure would be required to establish a web page with log-on facilities, tailoring it to end-users' needs, establishing regular performance reporting templates, and perhaps developing automatic email notification of new information posted to the site. Alternatively, the information could easily be published on the market information system.

446. If information disclosure rules are required on Transpower and generators, further one-off costs will be incurred to develop and consult on those rules, and further costs related to refining the rules over time as experience is gained with them.

Administration and compliance costs

447. The initiative would incur regular ongoing costs arising from the appointment of a service provider, who is independent of all market participants, to collate and report the outage and fuel information and for IT maintenance and provision of a help desk.

448. The initiative may require Transpower and generators to provide information to a higher standard of care than is currently required. This is likely to impose higher costs on them, in the form of additional resources to check the accuracy of their data and additional management time to approve the release of information. The initiative also envisages some large consumers providing planned outage information, which would impose additional compliance costs on them.

449. There would also be a modest ongoing cost for the time the Commission spends managing the service provider contract and responding, as required, to alleged breaches by Transpower, generators and large consumers with respect to their information provision obligations.

Information supply risks

450. As noted earlier, the initiative may result in Transpower and generator participants adopting a more conservative approach to outage schedule publication, such as by delaying publication until the firmness of a planned outage has a higher probability than occurs now.

451. On one hand these actions would reduce the lead-time between the date of publication and the date of outage, reducing the benefits to risk market participants identified above. On the other hand, risk market participants will be able to rely more on the information than under current arrangements. It is therefore important that any

rules of enforcement regime support the appropriate trade-off between timeliness and accuracy. Given these conflicting influences, it appears reasonable to assume these risks are immaterial to the net benefit assessment.

Other risks

452. There may be a small risk that a generator/retailer may misuse the publication to induce counterparties to CfDs into unfavourable contractual arrangements. For example, they might release false or out-of-date information initially, and then update it a few hours or days later, or they may delay publishing information. In practice, these actions are very unlikely to occur, as the behaviour required to effect such manipulations would be highly visible to the counterparty, and to enforcement agencies. These risks are not included in the net benefit assessment.

Risk of unsuccessful implementation

453. Although the technical implementation of this initiative is relatively simple, the development of the rules governing the disclosure of the outage and fuel information presents the greatest challenge. Consultation will be required with information providers to ensure that the disclosed information is robust but doesn’t cause the publication of the information to be significantly delayed.

6.4.6 Conclusions

Timeframe for implementation

454. If the Commission decided to adopt this initiative, it would need to formulate rules specifying how and when price sensitive information should be disclosed. The rules would probably take 6 – 12 months to prepare and another three 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.

Certainty of net economic benefits

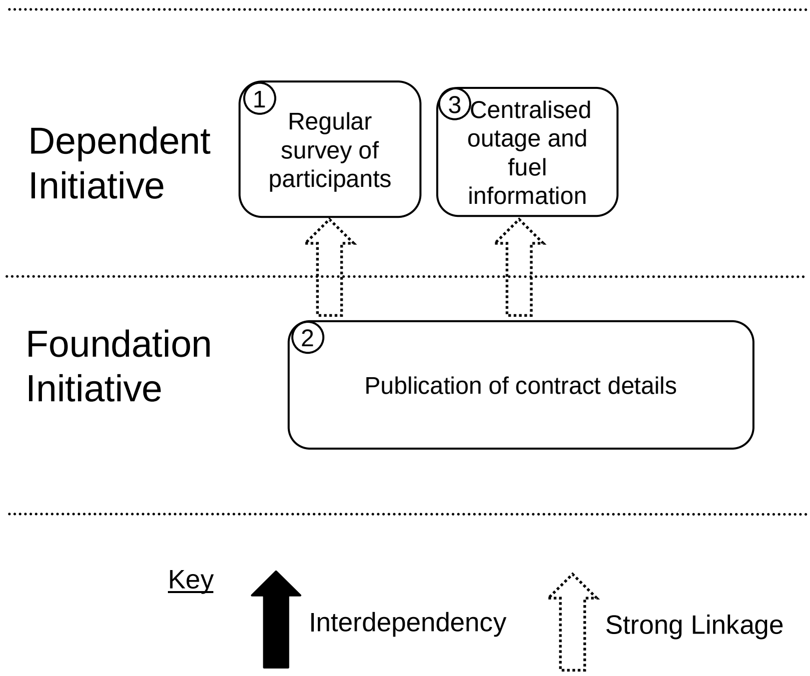
455. Centralised publication of fuel and outage information is a relatively simple initiative, and does not involve significant changes from current arrangements.

456. Although there are some risks that information suppliers may adopt a more conservative approach to the provision of information, these risks need to be weighed against the benefits of purchasers receiving more reliable information. On balance, these risks are unlikely to be material to the net benefit assessment.

Overall conclusion

457. The benefits of the initiative arise primarily from end-users adopting more efficient risk management practices, in regard to determining more efficient derivative prices and making more efficient use of derivatives to manage risk rather than FPVV contracts. The costs of the initiative relate primarily to IT development, and administration and compliance costs. Overall, the initiative appears likely to produce small-moderate net economic benefits.

Interdependencies and linkages



458. The centralised publication of outage and fuel information is closely linked with the publication of contract details as they both assist with the evolution of a more transparent and robust forward price curve. However, without the publication of contract details it would be hard to determine over time the likely impact of changes in outage and fuel information on prices and contractual terms.

6.5 Model derivative master agreements

Overview

Following initial discussions at the HMDSG, the major generator/retailers, MEUG and Business New Zealand are developing a model master agreement for derivative contracts. This initiative involves the Commission monitoring the development of the agreement, and publishing an independent assessment relative to the principal objectives and specific outcomes it has under the Act.

The development of a model master agreement is primarily directed at reducing barriers to participating in the derivatives market, by reducing the costs of negotiating derivative contracts. It should also make it easier for parties to compare contract prices if the contract publication initiative is adopted. By monitoring the development of the agreement, and providing an independent assessment of the final version, the initiative seeks to spread these effects to a larger proportion of the market.

The initiative is likely to produce net economic benefits for New Zealand by achieving greater voluntary use of the model master agreement, and by encouraging more efficient price comparability of derivatives and more efficient participation in the derivatives market. The initiative involves minimal cost and risk, as a model master agreement will be developed anyway, and the Commission can subsequently decide whether and how it wishes to support it.

6.5.1 Introduction

459. Contracts for electricity derivatives in New Zealand have several components. The most significant components of deals are specifically negotiated by the counterparties, and include details such as price, volume, location, force majeure etc. This information is usually contained in what traders refer to as a confirmation. Confirmations are signed by all counterparties to a specific deal and are legally binding.

460. Another component of derivative contracts is master agreements. Master agreements specify ‘the fine print’ underpinning derivative contracts, and are typically based on a master agreement from the International Standard Derivatives Association (ISDA) suite of contracts. Master agreements have a schedule attached, which specify certain conditions relating to deals done between the two counterparties to the master agreement. Most parties trading electricity derivatives in New Zealand use virtually identical ISDA master agreements, but the ISDA schedules can be quite different.

461. Currently, parties who wish to enter into derivative contracts bilaterally negotiate the schedule to the ISDA master agreement prior to entering into such contracts. The ISDA master agreement holds much of the fundamental information to a derivatives trade and the schedule enables participants to tailor this agreement to their individual needs. The length and complexity of negotiating each master agreement can become time consuming and expensive, particularly when costs for specialist advisors are included.

462. Since the HMDSG began considering the idea of a model master agreement, the major generator/retailers, MEUG and Business New Zealand have started to progress such an agreement and have committed resources to its development. . All consumers have been invited to participate in this process. This action should not be seen negatively as a reaction to thwart Commission involvement or to stave off regulatory intervention, but rather as a positive effort by these parties to develop practicable and effective solutions to improve the performance of the contracts market.

463. Given the industry's early response to the initiative it is difficult to determine whether it should be included in the baseline case or as an initiative of the HMDSG. We have adopted the former approach, and specified the initiative in this paper as one where the Commission provides and assessment of the agreement, and encourages use of the model agreement if it believes the agreement reflects the interests of all derivative market participants, not just those developing the agreement.

6.5.2 Promoter's view

Key problems

464. As section 3.3.2 discussed, one of the key problems inhibiting efficient risk management appears to be the high cost and complexity of negotiating an ISDA master schedule, which tends to create unnecessary barriers to entry to the derivatives market. Section 3.3.2 also pointed to the heterogeneity of derivative contracts in the OTC market, making it difficult to readily compare derivative prices. The promoters of this initiative believe that, by providing an assessment of the model agreement to all derivative market users, the Commission can further reduce negotiation costs and can make a wider range of derivative prices more readily comparable.

Possible economic rationale

465. In principle, participants from both sides of the risk management market can collectively negotiate a model master agreement without regulatory intervention. The economic rationale for the Commission assessing and supporting the development of a model master agreement rests on the view that there is significant public value at stake for all risk management market participants, and the voluntary collective approach may not fully reflect the interests of parties absent from the 'negotiating table'.

466. Whilst parties unhappy with the proposed model master agreement could collectively develop their own model master agreement, this is unlikely to occur because generators would support the model agreement they have helped develop. In other words, the generator/retailers, MEUG and Business New Zealand model agreement is likely to become the standard agreement.

467. Accordingly, the Commission can provide additional value by giving its own assessment of how the model master agreement relates to the principal objectives and specific outcomes of the Act. A favourable assessment will provide all market participants with confidence in the new agreement and could increase the general acceptance and adoption of the agreement. An unfavourable assessment will give the creators of the model master agreement, generator/retailers, MEUG and Business New Zealand, guidance on appropriate further development.

6.5.3 Specification of the initiative

468. As for other industry developed initiatives, usage of the model master agreement would be voluntary. The Commission would place the agreement and its assessment on its website and monitor usage among risk management market participants, as specified below.

The development process

469. Given generator/retailers, MEUG and Business New Zealand have already initiated a process to agree a model master agreement (the 'industry agreement'), the initiative in this paper is for the Commission to encourage those parties to keep the Commission informed of progress, and the processes they have followed in developing the model agreement. The Commission would review the industry agreement, and would discuss it with representatives of interested parties to evaluate whether the agreement achieves the Commission's objectives.

470. If the industry agreement is not developing as desired by the Commission, the only action it would take is to inform the parties that its assessment will outline what it believes to be the key deficiencies.

Monitoring of usage

471. Regardless of the outcome of the Commission's official assessment, the Commission would specify requirements for OTC market participants to disclose whether they are using the (relevant) industry agreement. This would be achieved by requiring disclosure to the Commission or other independent party, or by adding this disclosure requirement to the rules for mandatory publication of contract details specified in section 6.3 if that initiative were adopted.

6.5.4 Potential Benefits

472. The development of the industry agreement has the potential to improve the efficiency of risk management decisions, as it would lower the transaction costs of using derivatives, achieve more efficient price comparability, and lead to more efficient use of standardised derivatives. However, the benefits of this initiative relate only to the additional use of the industry agreement that the Commission may be able to achieve by publicly providing its assessment, over and above the benefits the industry agreement would achieve on its own account.

473. It may also be argued that the initiative is more likely to be implemented with Commission involvement. Considering that parties have already initiated a development process, this benefit is thought to be small and is not included in the benefits analysis.

Lower transaction costs

474. A primary benefit of the initiative is that it will reduce ongoing transaction costs for existing derivative market participants and new derivative market users, as fewer legal and management resources will be needed to initiate and conduct trades with counterparties. The scale of these cost savings will be shaped by adoption rates and this will be determined when participants trade off the cost savings from a standard master agreement against the greater flexibility that tailoring agreements provides.

475. The involvement of risk management market participants in the development of the industry agreement is likely to increase adoption rates relative to the case where the Commission specified its own master agreement. Likewise, official Commission assessment of the industry agreement provides parties not directly involved in the negotiations with an objective evaluation of the agreement.

More efficient price comparability

476. Another benefit of the industry agreement is that it would make it easier for derivative market participants to compare market prices from OTC and *EnergyHedge* trades. The economic benefits of the initiative therefore relate to the additional economic benefits arising from a larger portion of market participants using more efficient methods to manage their pricing risks than would occur without the Commission's assessment.

More efficient use of derivative contracts

477. The initiative may also increase participation in the derivatives markets, such as for *EnergyHedge* contracts and for OTC contracts.

478. *EnergyHedge* offers standardised derivates based on the master agreement of each issuer. If the issuers all adopt the industry agreement, then each generator/retailer may decide to trade more contracts among themselves on *EnergyHedge*.

479. Although the initiative could, in theory, encourage smaller generators, brokers, and end users to participate in *EnergyHedge*, this seems very unlikely under current arrangements where they would be required to post two-way prices in *EnergyHedge*. These potential benefits are therefore too uncertain to include in the net benefit assessment.

480. This initiative may increase market participants' ability to use derivatives obtained in the OTC market to manage pricing risks. The reduced transaction costs outlined above may encourage participants to use derivatives as an alternative to FPVV contracts.

6.5.5 Costs and risks

Costs

481. The costs of developing the industry agreement are not attributable to the initiative, as the initiative assumes an industry agreement will be developed anyway.

482. The costs associated with the initiative relate primarily to the costs of the Commission monitoring the progress of the parties negotiating the model agreement, understanding the consultation processes they have adopted to ensure fair outcomes have been achieved for all risk management market participants, and assessing the model agreement to provide guidance to all market participants.

483. The Commission will also incur costs monitoring adoption rates. These costs will be very small if use of the model master agreements is disclosed using the same platform as for the mandatory publication of contract details in section 6.3.

Risks

484. There is a low risk that the initiative may alter the decisions the voluntary grouping make regarding its industry agreement. For example, it may pursue an agreement

that it thinks will satisfy the Commission's objectives in order to reduce the risk of the Commission delivering an unfavourable assessment of its approach. This could reduce innovation and adoption rates of the agreement.

6.5.6 Conclusions

Timeframe for implementation

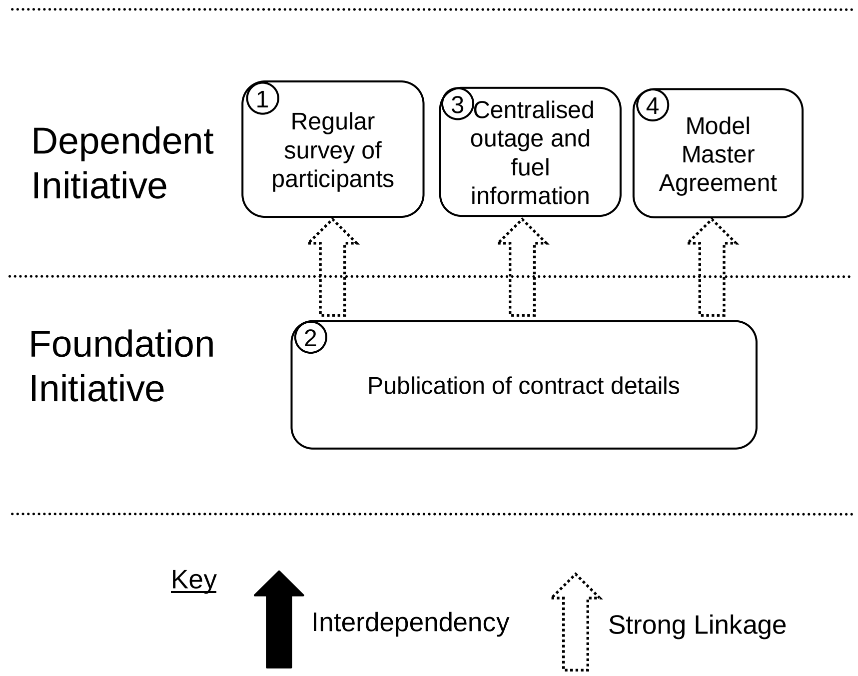
485. Development of the industry agreement is already progressing well within the industry. It is estimated that a final version of the industry contract will be finalised within 6 months.

486. The minimal requirements on the Commission means the initiative could be implemented within 3 months after the industry agreement has been finalised by the generator/retailers, MEUG and Business New Zealand.

Overall Conclusion

487. The initiative is likely to produce net economic benefits for New Zealand by achieving greater use of the industry agreement. The initiative involves minimal cost and risk, as an industry agreement will be developed anyway, and the Commission can subsequently decide whether and how it wishes to support it.

Interdependencies and linkages



488. The model master agreement may lower transaction costs in the derivates market and will deliver some benefit as a standalone initiative.

489. The model master agreement initiative has the potential to encourage a move towards more standardised CfDs in the derivatives market but the benefits of greater transparency and a more robust forward price curve will not be achieved without the publication of contract details. Although they are not interdependent the initiatives are strongly linked.

6.6 Development of *EnergyHedge*

Overview

This initiative involves the Commission inviting the owners of EnergyHedge to develop EnergyHedge's services. These developments may include: providing information of implied prices at other nodes using historical location factors, spread trading and the addition of strip trades. The initiative is therefore directed at improving the quality of information available to the market, and creating greater confidence in the competitiveness of the risk management market.

The initiative is likely to produce net economic benefits for New Zealand, as it encourages the owners of EnergyHedge to develop their trading platform in ways most likely to meet the needs of other market participants. They know that committing to an innovative expansion of EnergyHedge, and delivering on those commitments, would minimise their regulatory risks in regard to the risk management market, so they will adopt that approach if it is commercially viable for them to do so.

During this innovative development, the owners of EnergyHedge may decide that a continuation of the innovative approach is no longer commercially viable and reduce their development efforts to only minor enhancements. If this scenario occurs, EnergyHedge will need to provide compelling evidence to the Commission that there is very limited demand for trading standardised derivatives in New Zealand. Without this proof, the Commission may interpret EnergyHedge's reluctance for significant further development as an effort to retain differentiated contracts to protect a market power position.

The initiative involves minimal cost and risk. The primary risk is that the development of EnergyHedge does not deliver significant benefits and it imposes wasteful development costs on the owners of EnergyHedge.

6.6.1 Introduction

490. This initiative involves the Commission inviting the owners of *EnergyHedge* to state objectives for the development of *EnergyHedge.* The invitation would be extended through the issue of a letter from the Commission to *EnergyHedge*.

491. *EnergyHedge* provides a very simple and low cost mechanism for obtaining generator/retailer views on forward prices for standardised derivatives, out to 27 months, which parties can use in their negotiation of OTC derivative contracts. Although the current requirements for participation on *EnergyHedge*, especially the need to quote two way prices with a maximum spread of 10%, has resulted in participation by only the five generator/retailer members, participants do have the option to participate indirectly. *EnergyHedge* participants will trade with third parties on a non-discriminatory basis at prices referenced to *EnergyHedge*.

492. The primary aim of this initiative is to develop the existing *EnergyHedge* platform to grow the market's confidence in the robustness and efficiency of *EnergyHedge*'s forward price curve, rather than necessarily increasing the number of participants trading on *EnergyHedge*. The initiative would not need to develop *EnergyHedge* into a widely used trading platform in order to be considered a success.

6.6.2 Promoter's view

Key problems

493. As discussed in section 3.3.3, there is uncertainty about the competitiveness of the *EnergyHedge* market. The requirement for two-way pricing makes it unattractive for some parties to directly trade on it and this has resulted in only the five largest generator/retailers being members. Section 3.3.1, paragraph 253, also identified concerns about the robustness of the forward price curve produced by *EnergyHedge*.

494. The promoters of this initiative believe the requirement for *EnergyHedge* to outline specific development objectives would provide the Commission and other market participants with a useful basis for understanding *EnergyHedge's* development path. This would strengthen incentives on the owners of *EnergyHedge* to demonstrate the robustness of its price discovery process or provide compelling evidence that there is limited demand for trading standardised derivatives in New Zealand. Either way, the initiative should improve confidence in the efficiency of the risk management market.

495. The promoters of this initiative believe *EnergyHedge* has the potential to develop substantially, provided that costs associated with participation in the *EnergyHedge* market are reduced. In time this might include innovative measures to address credit risk and two-way pricing issues.

Possible economic rationale

496. The economic rationale for the initiative is based on the benefits that can be achieved from the development of an existing platform that has considerable support from major industry participants. Section 3.3.3 outlined some of the confidence issues that exist regarding the *EnergyHedge* forward price curve and the inability to directly access *EnergyHedge* pricing. *EnergyHedge* members would contend that concerns regarding the robustness of the forward price curve are unfounded and that all members are willing to provide indirect access to pricing referenced to *EnergyHedge*.

497. As outlined in section 3.2.5, it is critical in derivative markets to allow trading arrangements and contracts to develop in ways that best meet the evolving needs of participants, rather than take a static view as often occurs with prescriptive regulatory solutions. This suggests a voluntary approach, even if imperfect, may achieve more efficient outcomes than regulation.

498. It is useful to note that there appears to be consistency between the Commission's risk management market development objectives and *EnergyHedge* owners' vision "to enhance the electricity hedge market through the development and trading of standardised derivative contracts, for the benefit of participants and the electricity industry generally"[14]. This makes leveraging off an existing market arrangement likely to be a least cost approach.

499. This further suggests that asking *EnergyHedge* to commit to self-specified development objectives may achieve the most efficient outcomes.

6.6.3 Specification of the initiative

500. In line with the 'evolutionary' approach, the Commission would write to the owners of *EnergyHedge* inviting them to state specific objectives for the development of

[14] Refer www.energyhedge.co.nz

EnergyHedge. *EnergyHedge* would respond, outlining a list of short and medium term objectives.

501. The invitation would be via a letter to *EnergyHedge*, and would not involve rules requiring *EnergyHedge* to specify their objectives or to undertake their proposed development. The Commission would adopt a monitoring role on the specified objectives and their impact on the risk management market.

Possible response for EnergyHedge

502. The owners' response may include further consideration of the idea of a code of conduct for buyers and sellers and the development options outlined below:

   a. Providing information of implied pricing at other nodes using historical location factors. The implied prices will automatically update to changes in the *EnergyHedge* prices. This allows easier comparison of OTC contracts referenced at other nodes.

   b. Spread trading – this is likely to be in the form of calendar spreads. For example, trading the different time periods available on the curve rather than different geographical locations.

   c. Strip trades – to enable participants to simultaneously trade a series of contracts to achieve a desired annual price. To facilitate this, annual and two year prices could also be calculated from the contract prices and illustrated on the *EnergyHedge* website.

   d. Measures to grow market participants' confidence in the pricing information *EnergyHedge* delivers.

503. The development objectives are expected to exceed the developments outlined earlier in the description of the baseline market in section 5.1.3 of this paper.

504. The Commission would not directly endorse the development objectives for *EnergyHedge*. Progress would be measured by periodic reviews of the objectives that draw on any new information that is available at the time, this may include specific information that is obtained through the survey outlined in section 6.2.

505. If, during their review, the Commission were not satisfied with the contribution *EnergyHedge* was making to the development of the risk management market, or believed that there was no demand for the services it provides, the Commission would have the option to explore alternative regulatory measures.

506.

Monitoring of developments

507. Response to the Commission's invitation would be expected within three months of being issued and progress toward the declared objectives would be reviewed periodically. This review relates to the development of the *EnergyHedge* platform and the role it performs in the risk management market.

6.6.4 Potential benefits

Decisions by the owners of EnergyHedge

508. The owners of *EnergyHedge* could either adopt an innovative or conservative approach in response to the Commission's invitation.

509. The owners could choose an innovative approach and accelerate their development of *EnergyHedge.* This could be the best commercial option for the owners of *EnergyHedge* even if they believe there is limited underlying demand for *EnergyHedge*'s services. The reason is that investment in *EnergyHedge* could be viewed as an investment in reducing the risk of more intrusive regulation of the risk management market. If they implement significant development initiatives but fail to appreciably develop market depth and liquidity then they would have strong evidence for arguing against further regulation of the wider risk management market.

510. Under the conservative approach, the owners undertake minimal development of *EnergyHedge* on the justification that there is limited underlying demand for *EnergyHedge's* services. This approach could either be driven by commercial considerations, or by the view that more widespread use of standardised derivatives would erode their market power, if any exists.

511. If an innovative approach is adopted and the development of *EnergyHedge* is successful, then the primary benefits appear to be the prospect of:

- more efficient risk management decision-making; and
- better information for determining policies for the future development of the risk management market.

More efficient risk management decision-making

512. The innovative approach could potentially develop the depth and quality of price discovery in *EnergyHedge*, and develop market participants' confidence in the competitiveness of *EnergyHedge* prices. Both factors would bring more efficient risk management decision-making for the same types of reasons presented in section 6.3 regarding the publication of key contract details.

513. If the publication of key contract details initiative is successfully implemented, the resulting information could be incorporated into *EnergyHedge* to demonstrate the robustness of the forward price information. The innovative approach could also bring greater use of standardised derivatives through either direct or indirect participation in the *EnergyHedge* market, which would also improve efficiency.

514. These benefits will only occur if there is significant underlying demand for the services of platforms like *EnergyHedge*. In the UMR survey, just over 50% of purchasers indicated their organisation would be interested in using a centralised trading platform, which suggests there may well be significantly greater demand for *EnergyHedge*'s services if it could be configured to meet end-users' needs with acceptable participation requirements.

515. The probability of these benefits occurring from the initiative is uncertain at this stage. The difficulty is that it is necessary to develop *EnergyHedge* first to find out whether more *EnergyHedge* trading will occur and whether additional participants would join. It would also be plausible for *EnergyHedge* to change to a conservative approach if they believe there is no demand for standardised derivatives and that expanding *EnergyHedge* would be a waste of money. If this is their belief, they are likely to have

evidence to support this view and can easily demonstrate to the Commission that there is limited underlying demand for standardised derivatives.

Better informed policy-making

516. The second benefit of the initiative is that it may provide policy-makers with better information to make future decisions about the risk management market. A decision by the owners of *EnergyHedge* to adopt the innovative approach should provide policy makers with better information on whether there is indeed sufficient demand to justify the development of an open trading mechanism for standardised derivatives. Further, if the development of *EnergyHedge* is successful, policy-makers will be able to observe trading in a more liquid market than is currently possible. If the owners of *EnergyHedge* adopt a conservative implementation approach, this could indicate that owners are either not willing to take the commercial and reputational risks associated with the development of *EnergyHedge*, or it could indicate that the owners fear the loss of market power, if it exists.

517. Based on the above logic, there may be considerable benefit in implementing the initiative, as the reaction of owners, and the development of *EnergyHedge* will provide decision-makers with better information than is currently available. A successful implementation of the development objectives, may also change purchaser perceptions of generator/retailer market power, and increase their willingness to participate in the derivatives market.

6.6.5 Costs & risks

518. The primary costs of the initiative relate to the impact it may have on other options for developing trading arrangements.

Alternative platforms to EnergyHedge

519. The initiative could stifle entry of alternative trading facilities and inhibit the development of other tradable products. For example, *EnergyHedge* currently facilitates trading in a single product type of either quarterly or monthly durations. The Commission's monitoring role of *EnergyHedge* included with this initiative may stifle voluntary development of other tradable products until they are included within *EnergyHedge*'s development plans.

520. Having said that, other platforms are unlikely to be successful anyway as they do not have generator backing, which is necessary for market-making and trading to occur. On balance, these costs are likely to be insignificant.

Administration and compliance costs

521. The monitoring requirements of this initiative are very minimal for the Commission. The participants of *EnergyHedge* would incur the costs of writing a response to the Commission's invitation, and also the costs of achieving their objectives. While these costs are unknown, they should not be significantly bigger than the baseline case.

Other costs and risks

522. If market power exists, this initiative is unlikely to increase the market power of any particular generator/retailer, but there is a chance that, as a group, they could have more influence over the direction of the market than is desirable. The successful implementation of the *EnergyHedge* objectives could potentially strengthen their market position and enable them to resist future regulatory interventions to the risk

management market. Having said that, the Commission is an independent body and has significant regulatory making powers, if required. These considerations lead us to not consider these costs and risks in the net benefit assessment.

Risk of unsuccessful implementation

523. The voluntary nature of this initiative presents the greatest implementation risk. The previous analysis has outlined the incentives for *EnergyHedge* participants to commit to developing their platform but they are under no regulatory obligations to deliver these outcomes. Similarly, if the owners of *EnergyHedge* are successful with their developments there is no guarantee that development of the market will be successful if the potential demand has been over-estimated.

6.6.6 Conclusions

Timeframe for implementation

524. No formal rule development is required for this initiative and the delivery of the short term initiatives is expected to take approximately 6-12 months from dispatch of the Commission's letter inviting a specification from *EnergyHedge*.

Certainty of net economic benefits

525. The net benefit assessment is based on the reality that it is very difficult at this stage to determine whether further development of *EnergyHedge* is inhibited by a lack of underlying demand for *EnergyHedge* type contracts or by weak commercial incentives on the owners of *EnergyHedge* to develop it further. In any case, as the market is in excess of 90% hedged (as indicated in the UMR survey report), the lack of demand may be limited for good reason.

526. In this situation, receiving development objectives from *EnergyHedge* provides an opportunity for its owners to signal that they do not possess market power in *EnergyHedge*, by proceeding to accelerate development of *EnergyHedge* in innovative ways. If the initiative is successful, this would enhance direct and indirect trading volumes and participation in the *EnergyHedge* market, resulting in better information for future decision-making on the risk management market and further improving purchasers' willingness to participate in the derivatives market.

527. At worst, the initiative would result in very little change to *EnergyHedge* trading volumes and participation, imposing wasteful development costs on the owners of *EnergyHedge* if they adopt the innovative approach discussed above. Alternatively, if they adopt the conservative approach then the Commission would need to decide whether other initiatives to develop a standardised derivative market should be considered.

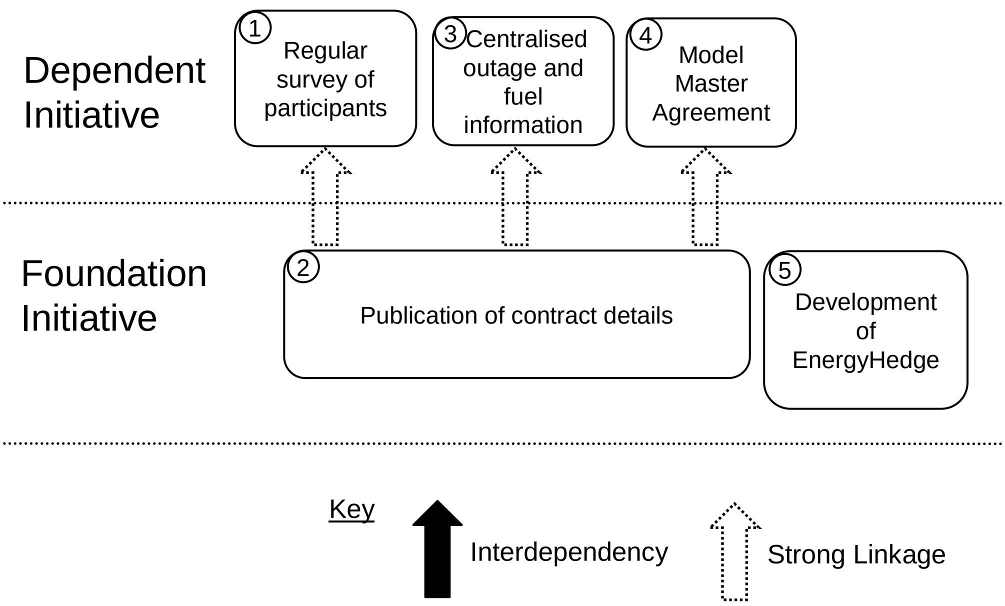
Overall conclusion

528. The initiative is likely to produce net economic benefits for New Zealand, as it encourages the owners of *EnergyHedge* to develop it further, in ways most likely to meet the needs of other market participants. Standard contracts and the potential for further developments may make *EnergyHedge* a more useful indicator of forward prices than the publication of contract details initiative outlined in section 6.3

529. The owners of *EnergyHedge* know that committing to an innovative expansion of *EnergyHedge*, and delivering on those commitments, would minimise their regulatory risks in regard to the risk management market, so they will adopt that approach if it is

commercially viable for them to do so. On the other hand, if they commit to conservative development objectives, then they know they will need to provide compelling evidence to the Commission that there is very limited demand for trading standardised derivatives in New Zealand. Without this, the Commission is likely to interpret their reluctance as an effort to retain differentiated contracts to protect a market power position. Again, the owners of *EnergyHedge* are likely to be best placed to provide that evidence.

Interdependencies and linkages



530. Although the value of this initiative would be substantially reduced if the initiative to publish contract details was not implemented, the development of *EnergyHedge* should still assist with the evolution of a more robust forward price curve.

531. The development of *EnergyHedge* has a moderate linkage to the publication of contract details and the central publication of outage and fuel information because they each assist with the evolution of a more transparent and robust forward price curve. *EnergyHedge* has a moderate linkage to the model master agreement as it should reduce transaction costs and simplify the negotiation process, removing a barrier to accessing *EnergyHedge*. The regular survey would provide information about the success of changes to *EnergyHedge* and indicate potential demand for additional services.

6.7 Understanding risk management

Overview

This initiative involves the Commission promoting greater purchaser understanding of electricity risk management, by developing and providing information programmes about the market and by publishing the availability of risk management training programmes. The initiative also involves the Commission requesting non-government organisations to facilitate certification of training providers and risk advisors.

The initiative is primarily directed at closing the knowledge gap identified in the 2005 UMR survey regarding the limited understanding by market participants of the benefits of using derivative contracts as an alternative means of managing risk.

The benefits of the initiative are uncertain, as there is some uncertainty about 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 tradable contracts. On balance, the initiative is likely to produce positive net economic benefits.

6.7.1 Introduction

532. This initiative involves the Commission promoting greater participant understanding of risk management in the New Zealand electricity industry, and facilitating certification of training providers and risk advisors. This initiative does not require the Commission to develop and implement new rules.

533. In particular, the initiative entails the Commission:

a. developing and providing information programmes to increase understanding of the market, the range of risks participants face, and the availability of training programmes to increase risk management skills; and

b. requesting non-government organisations (NGOs) to facilitate certification of training providers and risk advisors, agents against criteria to be developed in conjunction with the Commission.

6.7.2 Promoter's view

Key problems

534. As discussed in section 3.3.5, there appears to be a limited understanding of the fundamentals of electricity market risk in New Zealand, and a lack of knowledge of how to manage those risks. The promoters of this initiative believe the initiative will address these problems by raising general awareness of the critical importance of risk management knowledge and by assisting firms to select useful training providers and advisors.

Possible economic rationale

535. The economic rationale for the initiative rests on the view that derivatives markets exhibit significant 'chicken and egg' (or coordination) problems during early phases of

their development. Typically, a critical mass of active participants is required to sustain derivatives markets otherwise there is little pay-off for anyone to be involved.

536. In principle, market providers have incentives to overcome these coordination problems by encouraging the development of appropriate skills and knowledge among prospective participants. In practice, these incentives may be weak because market providers cannot secure property rights over such investments – trained or educated individuals are free to depart their firm and/or the market. This creates a divergence between private and public interests, which this initiative seeks to address in a light-handed fashion.

6.7.3 Specification of the initiative

537. The initiative entails the Commission:

a. developing and providing information programmes to increase understanding of the market, the range of risks they face, and the availability of training programmes to increase risk management skills; and

b. requesting NGOs to facilitate certification of training providers and risk advisory agents against criteria to be developed in conjunction with the Commission.

Certification of training providers and risk advisors

538. Another component of the initiative involves the Commission requesting NGOs to facilitate certification of training providers and risk advisors. For example, the Commission could approach Business New Zealand and the New Zealand Chamber of Commerce for their assistance in establishing a voluntary association of electricity market risk advisors, who would develop, in conjunction with the Commission, standards of behaviour and advice that parties would be required to attain before becoming members.

539. A similar association of training providers could also be established. The training association might also certify courses according to different levels of achievement.

Developing information programmes

540. The Commission would develop an information programme by contracting a suitably qualified person or organisation close to the electricity industry, knowledgeable on the risks, the practices, the obstacles and the risk management opportunities in the electricity market. The contractor would be tasked with developing an information guide for the Commission to publish on its website and distribute to current market participants. The Commission would draw on the expertise available in the HMDSG and other parties to review the pamphlet before finalising it.

541. The information pamphlet would contain a list of risk management training providers and their forthcoming courses. The Commission would identify training programmes by publishing a ‘request for registration of interest’ and include their details in the pamphlet.

542. The information pamphlet would also contain a list of risk advisors – parties available to provide advice on risk management in relation to the New Zealand electricity industry. As for the training programmes, the Commission would identify risk advisors by publishing a ‘request for registration of interest’ and include their details in the pamphlet.

543. As discussed below, the Commission would encourage certification of training providers and risk advisors by clearly identifying in its pamphlet parties' certifications.

6.7.4 Potential benefits

More efficient participation in the derivatives market

544. Increased training of purchasers, and greater use of risk advisors, is likely to support more widespread participation in the derivatives market. As increased use of derivatives would be voluntary, it should increase efficient risk management decision-making as participants will only switch to spot and derivatives when the benefits exceed the costs of moving off FPVV contracts.

Innovation

545. Greater use of risk advisors in response to this initiative may encourage advisors to provide new services, such as monitoring risk and opportunities for their clients, and perhaps establishing brokering platforms for trading standardised derivatives. Risk advisors are also likely to encourage energy purchasers to consider the full range of risk management options, including derivative contracts when suitable for the customer.

Competition

546. Increased demand for risk management training and advice is likely to attract new entrants to the training and advisory markets, increasing competition in those markets and reducing the cost of those services to the industry.

6.7.5 Costs and risks

Establishment and administration costs

547. The Commission would incur costs of developing and providing the information pamphlet, and updating it as required.

548. The Commission and NGOs (or the voluntary associations) will also incur one-off costs of developing certification standards, and on-going costs of assessing new membership applications. Training providers and risks advisors will incur ongoing costs of complying with the certification standards.

549. The initiative reduces promotion costs for training providers and risk advisors, particularly as the pamphlets would provide targeted advertising to electricity purchasers and generators. Our expectation is that most, if not all, training providers and risk advisors would seek to be listed in the Commission's pamphlet.

550. 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. Hence, most training providers and risk advisors would incur certification costs.

Certification risks

551. There is a risk the certification requirements may increase barriers to entry in the markets for training and risk advice. For example, members of a voluntary association may use their assessment processes to inhibit entry from more innovative (or simply different) providers.

Risk of unsuccessful implementation

552. The key risk associated with this initiative is that despite efforts to promote risk management and the use of certified experts, few organisations that do not already practice active risk management will respond to the initiative.

6.7.6 Conclusions

Timeframe for implementation

553. As no formal rule development is required for this initiative, it is expected to take approximately 6-12 months from time of approval for training courses, accreditation and associated literature to be made available.

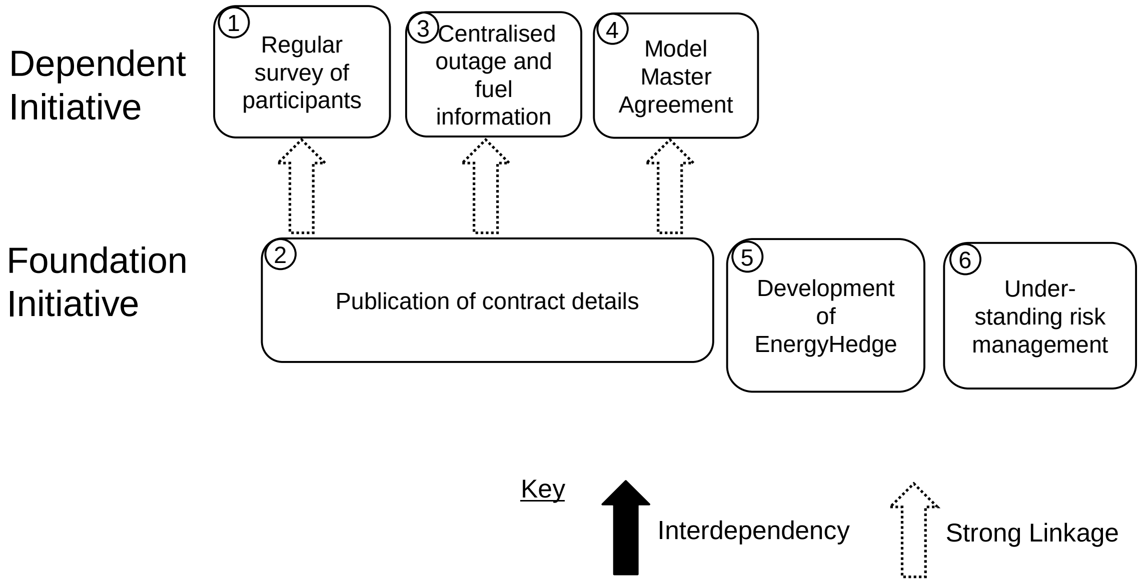
Certainty of net economic benefits

554. The benefits of the initiative are difficult to quantify and rely largely on the success of the Commission promoting greater risk management awareness among electricity purchasers and generators who are exposed to spot and TOU prices. The initiative involves very low establishment costs, and can be easily discontinued if it proves ineffective at stimulating greater interest in tradable contracts.

Overall conclusion

555. The benefits of the initiative are uncertain, as there is some uncertainty about how effective the Commission, training providers and risk advice agents 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 tradable contracts. On balance, the initiative is likely to produce positive net economic benefits.

Interdependencies and linkages



556. This initiative is designed to improve the human infrastructure of the risk management market and therefore help assist with the development of an efficient risk management market.

557. Facilitating an improved understanding of risk management has weak linkages to all previous initiatives but no interdependencies.

6.8 Mandatory use of standardised contracts for differences

Overview

This initiative would make it mandatory for risk management market participants to use a standardised CfD to trade base load energy. The contracts would be based at one of three locations, with maturities out to five years. Participants would be free to trade the standardised CfDs through whatever market they wish, such as through the OTC or EnergyHedge markets, and they would be free to trade other contracts for non-base load energy.

This initiative is primarily directed at addressing purchaser perceptions about a lack of competitiveness and liquidity in the derivatives market. It also seeks to create a robust forward price curve for energy, by concentrating all trading of base-load energy to a standardised CfD with multiple maturities.

Mandatory use of standardised CfDs involves what appears to be a fairly simple but radical intervention in the risk management market. However, there are several structural issues with the initiative for which solutions have not been apparent despite a degree of consideration.

Although, theoretically, risk management participants should be able to achieve the same commercial outcomes as under current arrangements by trading residual contracts, in practice, this may not be the case. This renders the economic benefits of the initiative uncertain, as it carries significant commercial risks for many market participants.

The potential benefits of the initiative depend critically on views about the appropriate base case for the standardised derivatives market. It also depends on whether some kind of transmission hedge is available to help participants manage locational price risk. The analysis considers three base cases and concludes that uncertainty about which case is applicable means the expected benefits of the initiative are likely to be small. Moreover, the economic benefits of the initiative are likely to be minimal if other initiatives discussed in this paper are adopted.

With the prospect of the initiative creating unintended and adverse commercial outcomes for generators, combined with the need to resolve some structural issues, the overall conclusion is that the prudent approach would be to adopt a 'wait and see' approach, to provide time for the derivatives market to evolve in response to the other initiatives discussed in this paper.

6.8.1 Introduction

558. The previous initiatives focused primarily on facilitating the evolution of the derivatives market, with rule-based intervention limited to requirements for parties to publish contract details. Most of those initiatives are considered likely to lead, over time, to greater voluntary use of standardised derivatives at a small number of trading nodes, provided location risks are addressed effectively.

559. In contrast, the initiative in this section would make it mandatory for risk management market participants to use a standardised CfD if they wish to trade base load energy. The contracts would be based at one of three locations, with maturities out to five years. Participants would be free to trade other contracts, provided they are not base load energy CfDs. They would also be free to trade base load contracts through whatever market they wish, such as through the OTC or *EnergyHedge* markets.

560. Most respondents to the UMR survey believe that a “standard hedge product available through a centralised trading platform to all counterparties would add liquidity and transparency to the hedge market”. There were some opposing views between medium and large purchasers and generator/retailers. One generator/retailer answered that it would increase transparency, but not liquidity, and another said that the majority of hedges were customised to individual needs and that a standardised CfD was unlikely to gain liquidity.

561. The question posed in the UMR survey included the use of a centralised trading platform and further work is required to clarify whether participants see benefit in a mandatory standardised contracts regime without the use of a centralised trading platform. Further investigation is also required to understand whether participants actually require bespoke contracts and whether the introduction of a transmission risk management product would lead to increased standardisation. The following analysis focuses only on the introduction of standardised CfDs.

562. This initiative would require the Commission to develop and administer new rules, and would probably require changes to the Act to empower the Minister to approve such rules.

6.8.2 Promoter’s view

Key problems

563. An important feature of standardised CfDs is that purchasers can easily compare offers and choose the most competitive one, assuming there are no credit issues. All they have to do is choose the lowest price offer available to them. Promoters of this initiative therefore believe it will facilitate greater confidence in the competitiveness of the risk management market, a problem identified in section 3.3.3, because it will make it very easy to compare price offers from competing providers and with historical prices for the same contract. In this situation, it will not be possible for generator/retailers to sustain even small price differentials from their competitors.

564. Promoters of this view also believe it will enhance derivative market liquidity by concentrating derivative trading for base load energy in a single product. The more trades conducted in any product, the easier it is for parties to adjust their contract positions without depressing market prices against them.

Possible economic rationale

565. The economic rationale for mandatory standardised CfDs can be based on either one, or both, of the following hypotheses:

a. The ‘chicken and egg’ hypothesis. The ‘chicken and egg’ nature of financial markets means the electricity derivatives market may be stuck in a suboptimal equilibrium, and requiring regulatory intervention to shift it to a more efficient equilibrium. Once liquidity has developed in the market for the standardised CfDs, participants will continue to use it even without rules requiring them to do so; and

b. The market power hypothesis. Under this hypothesis generator–retailers exercise market power in the derivatives market by selling differentiated contracts. If true, requiring generator/retailers to trade a standardised CfD is expected to achieve more efficient risk management outcomes. However, even with mandatory trading of standardised CfDs, market power could still be exercised in the contract covering delivery of energy from the trading hub to the actual location of the purchaser.

566. The Commission have not determined that either of the above hypotheses is necessarily valid, and therefore, are not suggesting that conditions exist which justify the use of mandatory standard CFDs. At this stage, the hypotheses are only for analytical purposes.

567. As in previous sections we do not choose between these hypotheses, but rather consider how they affect the evaluation of net economic benefits.

6.8.3 Specification of the initiative

568. Under this initiative the rules would specify the details of the standard CfD, who would be required to trade it, how their obligations to trade the CfD would be determined, and how compliance with the rules would be monitored and enforced.

Specification of the standard contract

569. The CfD would be referenced to monthly average prices at one of Benmore, Haywards, or Otahuhu nodes. The standard CfD would use the model master agreement developed under the initiative in section 6.5.

570. As in section 6.3, publication of contract trades would be mandatory.

571. Apart from the allowance for references to Benmore, Haywards or Otahuhu, and the inclusion of an FM clause, the standard CfD would have the same terms and conditions as the derivatives currently traded in *EnergyHedge*:

a. Start and end dates aligned with each calendar month;

b. CfDs for the current quarter would be specified in monthly lots, with longer maturity CfDs out to a maximum of 27 months, specified in quarterly lots. Beyond that, the standard CfD would be specified in annual lots out to five years;

c. Specified quantities, with the minimum size being 0.25MW and increments being in multiples of 0.25MW[15];

d. Simple prices, with no other fees, indexations or pass-through provisions;

e. No suspension clauses;

f. Settlement on the 20th of the month; and

g. A set of credit arrangements that produce equivalent credit risk outcomes as currently faced by *EnergyHedge* participants, such as acceptable credit ratings, bank guarantees, and other prudential requirements.

Who must trade the standardised CfD?

572. The obligation to use the standard CfD would apply to all retailers, generators and direct connect participants over 10GWh/annum gross load. There would not be any

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[15] Hence, FPVV contracts are not standardised contracts as defined in this paper.

requirement on these parties to cover energy price risk using these CfDs, but if they use CfDs to cover energy price risk then they have to use the standard CfD (as well as other products if they wish).

Determination of trading obligations

573. Unlike the mandatory hedging initiatives outlined in the GPS and analysed in sections 6.11 and 6.12, this initiative doesn't specify minimum volumes of standardised CfDs to be offered by generator/retailers or bought by purchasers. Rather, the initiative simply requires that all energy trading which includes a baseload component comprises at least the standardised CfD, with participants free to trade residuals in addition to their standardised CfD to achieve desired risk cover.

Example 1: location residuals

574. For example, an industrial consumer at Kawerau may wish to cover its price risks for 10MW of energy delivered at Kawerau during January 2006. Currently they could do this by obtaining a 10MW CfD for January 2006, referenced to the wholesale spot price at Kawerau. As only two generator/retailers have local generation near Kawerau, they may be the only parties willing to offer CfDs at Kawerau.

575. Under the initiative proposed in this section, the consumer would achieve the same risk positions by purchasing two CfDs: a standard CfD for 10MW, referenced to Haywards; and a 10MW transmission CfD to cover the price difference between Haywards and Kawerau. As above, only two generator/retailers may be willing to offer transmission CfDs for Haywards to Kawerau, but many more generator/retailers are likely to offer the standardised CfD at Haywards.

576. If no generators were located in Kawerau, the industrial consumer may find it problematic to purchase a suitably priced transmission CfD. Section 7 of this paper explores two options for the introduction of transmission hedge initiatives that would go some way to alleviate locational price risk.

Example 2: peak-load residuals

577. Another example would be where an industrial consumer at Otahuhu wanted to purchase a profiled CfD to match its load pattern. For example, the consumer may expect to have load of 10MW at night and 14MW during the business day during the first quarter of 2006. Currently the consumer can buy a sculptured CfD for the first quarter of 2006 to match its expected load profile, referenced to the Otahuhu price.

578. Under the proposed initiative, the consumer would achieve its desired risk position in one of two ways. It could purchase a 10MW standard CfD and a 4MW peak-load CfD, both referenced to Otahuhu; or purchase a 14MW standard CfD and sell a 4MW off-peak CfD, both referenced to Otahuhu.

Comment

579. Any fixed quantity contract can be split into two or more contracts. The above examples illustrate simple cases where there is only one point of difference between the standard contract and the desired contract. If there are two points of difference, such as the consumer's need for a profiled contract at Kawerau (rather than a standard contract at Haywards), then three contracts are needed: a standardised contract at Haywards, a peak load contract at Haywards, and a profiled transmission hedge from Haywards to Kawerau.

Trading mechanism

580. As with any other contracts, parties would be free to trade the standard CfD through any market platform they wished.

Transitional arrangements

581. Transitional arrangements may be needed to implement this initiative. For example, the regime would need to be phased in over time as existing contracts expire, and so the full effect of the initiative could take some time to materialise.

Monitoring and enforcement

582. Compliance with the obligation to use the standard CfDs would be monitored by the Commission, using information from the publication of contract details as specified in section 6.3. Provided risk management market participants abide by the disclosure rules, the publication of contract details will reveal any transactions which have terms and conditions materially different from the terms and conditions of the standardised contracts.

583. The disclosure requirements in section 6.3 would be bolstered with a requirement for contract sellers to disclose to the Commission (but no one else) the identity of the organisations undertaking each transaction. This is necessary to allow the Commission to monitor compliance with the rules on an ongoing basis, rather than rely on random audits.

584. Parties that fail to comply with the rules would be alleged to be in breach of the rules. The normal process for dealing with alleged breaches as outlined in the Regulations would then be followed.

Structural challenges

585. There are a number of structural issues with this initiative that have been identified but no solutions have been specified. These include:

a. definition of a CfD – a highly detailed definition of a CfD will be required to ensure parties are clear about their mandatory requirements. Even if this is specified, there is a high probability that participants will circumvent the rules unless the initiative meets their needs.

b. definition of base load – if parties are contracting a combination of base load, peak load and transmission hedge, how would the base load component be identified?;

c. pricing split when a contract contains base load and another component (peak load, transmission hedge); and

d. credit risk management and impact on pricing.

586. Further work is required to determine whether a practical solution actually exists, but the following analysis assumes that this can be successfully resolved before implementation.

Implementation

587. Implementing this initiative would require the Commission to develop and administer new rules. If the rationale for these rules is based on the view that current market outcomes reflect suboptimal policy decisions, then the market in standardised CfDs would be self-sustaining once it reaches critical levels of liquidity. On this basis, the

new rules would include a sunset clause removing the initiative after a period of time, such as ten years following the commencement of the rules.

6.8.4 Potential benefits

588. The potential benefits of the initiative depend critically on views about the appropriate base case for the standardised derivatives market. The following analysis considers three hypotheses or cases: the market is stuck in a suboptimal equilibrium due to coordination problems (case 1); the market outcome is suboptimal due to generators/retailers exercising market power (case 2); and neither of the above (case 3).

Case 1: efficiency gains from removing coordination problems

589. As discussed in section 6.8.2, this case assumes the standardised derivatives market exhibits coordination (i.e., ‘chicken and egg’) problems, leaving it in a sub-optimal equilibrium. Under this assumption, introducing mandatory standardised CfDs would potentially bring efficiency gains by focusing all risk management contracting above 10GWh/annum on a single CfD product, creating a more liquid standardised derivatives market.

590. In this case, the potential benefits of the initiative depend on whether derivative market participants will switch to alternative methods of managing their spot price risks (such as vertical integration) or reduce their target hedge cover levels, rather than comply with the requirement to trade standardised CfDs. In general, it seems unlikely the initiative would result in large scale switching to alternative risk management methods as some purchasers have indicated they see significant advantages from buying standardised contracts, and they can use residual CfDs to manage risks not covered by the standardised CfD (although see section 6.8.5 for arguments that generators will not trade residuals).

591. Given these assumptions, efficiency gains would arise from:

a. more efficient and robust forward price curves for energy;

b. greater confidence in the competitiveness of the risk management market, encouraging more efficient participation in the derivatives market; and

c. a more liquid standardised derivatives market, giving participants greater confidence they can liquidate their portfolios at market prices, which again encourages more efficient participation in the derivatives market.

More efficient and robust forward price curves

592. The addition of a standard energy CfD would greatly enhance the benefits of the contract publication initiative in section 6.3, by enabling purchasers to easily construct forward price curves without normalising the terms of generators’ offers, such as removing the impact of FM clauses on contract prices. Relative to the baseline case in section 5, there would be significant improvements to obtaining a credible and robust forward price curve at a limited number of nodes.

Greater confidence in the competitiveness of the contracts market

593. If perceptions about the competitiveness of the derivatives market are misperceived, the publication of mandatory standard CfDs would dispel those misperceptions and increase confidence in the competitiveness of the risk management market. It would be simple, for example, for purchasers to choose the most competitively priced offers.

This would lead to more efficient participation in the trading of energy CfDs because purchasers would be more confident in the deals offered.

Greater liquidity of the derivatives market

594. The concentration of energy CfDs to three locations has the potential to significantly increase liquidity at these nodes. At the current time, there may be participants who would like to adjust contract positions in the secondary market but tailored contracts, which characterise the current market, make it difficult for liquid secondary markets to develop.

595. If this assertion is true, the introduction of standardised CfDs will allow participants to manage a higher proportion of their energy requirements through standard CfDs, with the potential for increased market liquidity at those nodes.

596. Greater market liquidity allows individual market participants to liquidate their portfolios at prevailing market prices. This provides market participants with greater confidence to use derivatives to manage their risk position, as they know they won't be penalised if they need to sell a large portion of their portfolio. It also provides market participants with a more robust basis for using mark-to-market accounting standards. Both factors enhance the efficiency of risk management decision-making.

Case 2: efficiency gains from reducing market power concerns

597. This case assumes that generators exercise market power in the derivatives market by selling differentiated contracts that are intentionally hard to compare with other offers. In this case, the introduction of standardised CfDs would enable purchasers to easily compare CfDs and choose a generator offer based on price. This places maximum pressure on generators to offer competitive prices on the standardised CfD.

598. Another market power issue is related to trading FPVV contracts which are unable to be resold since volumes are limited to metered flow at a specific customer connection. The ability to prevent resale enables generators to maintain discriminatory pricing between new entrant retailers and existing large customers. Contracting with CfDs however, does not enable the same degree of price discrimination, although CfDs do not need to be standardised to achieve this.

599. The competitive position for transmission risk management products in the OTC market will not change but more generator/retailers are likely to offer the standard CfDs at the three reference nodes. In particular, if a local generator is the only participant that has the ability to offer a transmission hedge, they may be well positioned to offer competitively priced energy CfDs and expensive transmission CfDs. The net effect may be little different from the situation without mandatory standardised contracts.

Case 3: there are no efficiency gains

600. A realistic possibility is that neither coordination problems nor market power concerns explain the lack of a standardised derivatives market for consumers in New Zealand. Rather, under this case the lack of such a market arises from the small size of the New Zealand market, making it unlikely that even a well supported market would be liquid. Without reasonable levels of liquidity, standardisation brings insufficient commercial benefits relative to bespoke derivatives.

601. In this case there are no efficiency gains from adopting mandatory standardised contracting.

6.8.5 Costs and risks

Implementation costs

602. If publication of contract details in section 6.3 is adopted, there is no incremental IT cost associated with mandatory standardised CfDs.

603. The main implementation costs would be reaching agreement on the terms and conditions of the standardised CfD.

Compliance, monitoring and enforcement costs

604. The initiative would require generators and purchasers to amend their current market practices to comply with the new rules. There would be a one-off costs to create new working practices but also an ongoing increase in operational costs as generators would now be required to negotiate multiple contracts to fulfil a risk position that was previously delivered under a single contract.

605. The Commission would also incur ongoing monitoring and enforcement costs in regard to paying for auditors and enforcing the rules via the Rulings Panel.

Reduced cover for spot market risks

606. If the initiative increases the cost of achieving the desired risk positions, then derivative market participants may decide to obtain a lower level of overall cover against their spot market exposure. For example, both industrial consumers and generator/retailers may to decide to hedge a lower portion of their expected load or generation than they currently do. There is a significant risk that parties will revert to FPVV contracts.

607. One reason contracting costs would increase is that standardisation of the credit terms in the standard CfDs places the onus on purchasers to obtain third party credit sufficient to meet the credit requirements currently required by *EnergyHedge*.

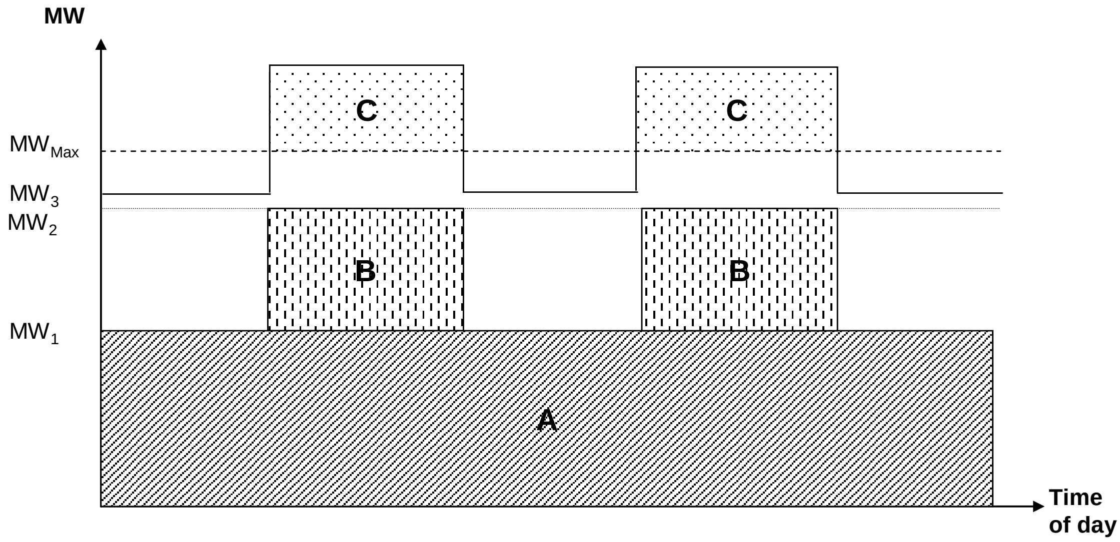
Greater use of inefficient risk management mechanisms

608. There is a risk that participants may switch to less efficient risk management mechanisms after the introduction of standardised CfDs. This would be likely to occur if they are unable to use residual contracts to cover their residual risks.

609. By their nature, standardised CfDs will contain terms and conditions that are not tailored to the particular needs of each market participant. In principle, contracting parties should be able to negotiate residual contracts to obtain the same position they would achieve under current arrangements. In practice, generators may be unwilling to offer residuals unless they have also offered the base energy contract. Figure 15 is a very simplified example of why a base load generator with maximum capacity MW_{max} may not want to offer only a peak contract.

610. Assume that a generator already has base load CfDs, A, up to a total output of MW_1. The sale of a peak CfD, B, would reduce the capacity available for base load CfDs, to $M_{Max} – MW_2$,and the generator would probably be unwilling to offer a base load CfD for $MW_3 – MW_1$ because area C would breach its maximum generation capacity. In effect, residual contracts would ‘crowd out’ base load contracts. For this reason, a generator is unlikely to offer a residual CfD for B without the underlying base load CfD.

Figure 15: Residual contracts 'crowding out' base load contracts



611. In practice total generation matches total demand, so in aggregate generators have sufficient generation to offer peak residuals to match purchaser requirements without compromising their aggregate ability to issue base load contracts. The problem for individual generators is that they cannot be sure of their future generation profile, and so assume a flatter profile than occurs in practice. Nevertheless, as standardised derivatives are common in other jurisdictions, the 'crowding out' problem seems unlikely to be insurmountable.

Increased negotiation costs

612. For difficult risk positions, the initiative may increase overall negotiation costs. For example, if it is difficult and costly under current arrangements to negotiate a bundled CfD for Kawerau, then it will become more difficult and costly to negotiate a location residual for Kawerau. Although the standard CfD should be readily available with very minimal negotiation costs – since price is the only negotiable term – the overall negotiation costs may increase under the initiative.

613. These increased negotiation costs may encourage derivative market participants to use alternative methods for covering their spot market risks, reducing demand for derivative contracts.

614. For example, industrial purchasers may decide they can obtain cheaper and more effective cover from FPVV contracts, or from installing co-generation plant. Similarly, generator/retailers may place greater emphasis on achieving a regionally balanced generation and load portfolio. These types of moves would reduce demand for derivative contracts.

615. During the development of this initiative, some participants have indicated they see benefits in a standard contract but further consultation would be required to outline some of the practical implications.

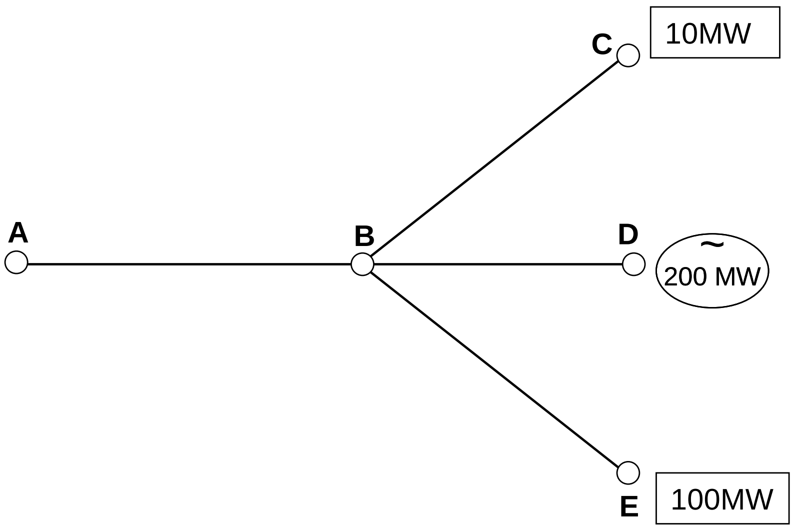
Commercial implications for generators

616. In the current risk management market, the ability of generators to reference energy CfDs at the generation source enables them to assume no locational price risk when

trading. The obligation to offer at only three nodes will introduce a locational price risk for the majority of generators and they will need to consider how to address this risk.

617. An example is shown in figure 16. If we assume that node A is the reference node, the generator at D will no longer be able to offer 100MW of energy CfDs at D, with no location risk, but must offer all CfDs at A. In the absence of a transmission hedge, this generator will assume the transmission risk between A and D. The introduction of this location risk may result in a reduction in the number of energy CfDs offered or increase the price for the contracts referenced at A.

Figure 16: Generator location price risk using standardised CfDs



Risk of unsuccessful implementation

618. A clear majority of all respondents in the UMR survey said a centralised trading platform that provided standard CfD products would add liquidity and transparency to the hedge market. Further work is required to understand participants' views on the use of mandatory standardised CfDs without a centralised trading platform and whether parties understand the secondary effects explained in this paper.

619. The transitional phase associated with this initiative, as existing energy contracts expire, presents probably the greatest implementation risk. Early adopters of standardised contracts will not experience the full benefits until a critical mass is achieved but may have to initially tolerate some additional cost. If the benefits do not materialise in the medium term, participants may explore some of the alternatives outlined in the previous section, FPVV contracts for example, and the implementation of the initiative would quickly unravel.

6.8.6 Conclusions

Timeframe for implementation

620. This is the first significant mandatory initiative proposed in this paper and as stated in the GPS, the Commission may only recommend regulations if it has first established that there are significant problems that are not resolvable through voluntary arrangements and co-operation. For this reason, the Commission would be required to introduce initiatives that are less interventionist, possibly those suggested in sections 6.2 to 6.7, before this initiative can be implemented.

621. If this initiative was to be implemented, it is envisaged that it would require the Commission to develop and administer new rules, and would probably require changes to the Electricity Act to empower the Minister to approve such rules. If changes to the Electricity Act are required these are likely to take approximately 12 to 18 months.

622. Once new rules are implemented, the structure for standardised CfDs could be established over a relatively short period but it will take longer for the market in standardised CfDs to reach a critical mass as existing contracts would need to expire. The full benefits of this initiative, including a more robust FPC and greater liquidity, are expected to be realised approximately 18 months after the implementation of the rules.

Certainty of net economic benefits

623. Mandatory use of standardised CfDs involves what appears to be a fairly simple but radical intervention in the contracts market. However, there are several structural issues with the initiative for which solutions have not been apparent despite a degree of consideration. There is some prospect the initiative may produce net economic costs due to unintended side effects that are difficult to foretell at this stage.

624. The predicted liquidity and price benefits associated with this initiative result from the concentration of trading at three locations. These benefits arise if the derivatives market suffers coordination problems (case 1 above) or market power problems (case 2 above), but it is difficult to know whether those problems exist or are significant. An alternative, and quite realistic possibility, is that New Zealand is too small to sustain a liquid derivatives market (case 3 above), in which case there are no economic benefits from introducing the initiative. On balance, then, the expected economic benefits from the initiative could be very small.

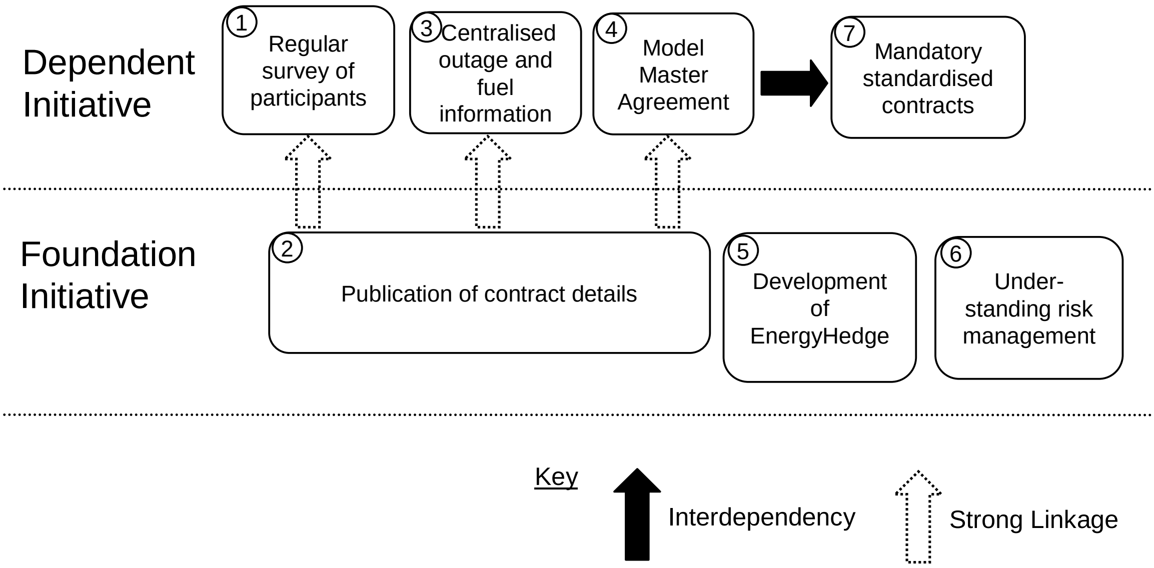
625. The net benefit assessment in this section is based on the assumption that publication of contract details will be approved as an initiative and participants will use standardised CfDs to manage their risk. Under this assumption, many of the economic benefits of the initiative may occur anyway from publishing contract details and from the voluntary development of a model master agreement.

Overall Conclusion

626. Making standardised CfDs mandatory carries significant commercial risks for contract market participants. Although parties should, theoretically, be able to use residuals to achieve the same contract positions as they can under the current arrangements, the initiative would require significant changes in existing contracting arrangements and practices.

627. These considerations suggest the Commission should adopt a ‘wait and see’ approach, to provide time for the derivatives market to evolve in response to the other initiatives recommended in this paper which are anticipated to provide more positive and efficient outcomes.

Interdependencies and linkages



628. The creation of a model master agreement is required before the mandatory standardised contracts initiative could be introduced and there is an obvious interdependency between these two initiatives.

629. There is a weak link between the mandatory use of standardised contracts and the publication of contract details and the central publication of outage and fuel information because they each assist with the evolution of a more transparent and robust forward price curve.

6.9 Exchange-based trading of mandatory standardised contracts

Overview

This initiative would make it mandatory for the standardised CfDs discussed in the previous section to be traded on a mandatory exchange, rather than through the OTC market, EnergyHedge, or any other trading platform.

This initiative is primarily directed at addressing purchaser perceptions about a lack of liquidity in the derivatives market. This is addressed by concentrating the trading of all standardised CfDs to a single platform, and to require the platform to act as an exchange so that credit risk is managed centrally. By seeking to create a more liquid market, the initiative also seeks to create a more robust forward price curve for base load energy.

The net economic benefits of the mandatory exchange initiative are uncertain because of uncertainty about whether it reduces credit risk costs sufficiently to justify the costs of the exchange. If trading volumes turn out to be low then the costs of the initiative are likely to exceed its economic benefits. There are also structural issues with the standardisation of contracts that would need to be addressed before the mandatory exchange initiative could be implemented.

Given these uncertainties, and the prospect that other initiatives may voluntarily increase standardisation of contracts, the prudent approach is to defer further consideration of the initiative to provide time for the derivatives market to evolve in response to the other initiatives recommended in this paper.

6.9.1 Introduction

630. The initiative presented in this section is to make it mandatory for spot market participants to trade standardised energy CfDs on a mandatory exchange. Participants would be free to trade whatever non-standard products they wish, and on whatever platform they wished.

631. Under the previous initiative, standardised energy CfDs could be traded through the OTC market, or from brokers in the OTC market, or from *EnergyHedge*. All of these trading mechanisms leave credit risk with the counterparties involved in the CfD trades, whereas credit risk under an exchange system is carried by the exchange itself – credit risk is centralised rather than decentralised or bilateral.

632. This initiative would require the Commission to develop and administer new rules, and conduct a tender for parties to operate the exchange. This initiative may require changes to the Electricity Act to empower the Minister to approve such rules.

6.9.2 Promoter's view

Key problems

633. Promoters of this initiative believe it addresses concerns about low liquidity in the derivatives market and the lack of a robust forward price curve for energy derivatives

(section 3.3.1), by concentrating all trading of energy CfDs to a single type of CfD and a single exchange.

Possible economic rationale

634. The economic rationale for making exchange-trading mandatory rests on the view that a critical mass of participants is required to achieve efficient and sustainable liquidity levels.

635. By making exchange-trading mandatory, promoters of the initiative believe it will create a focal point for trading all standardised CfDs and would better deal with the credit risks inherent with standardised CfDs, creating a more efficient equilibrium that would be self-sustaining once liquidity in the market for the standard CfD has reached reasonable levels.

6.9.3 Specification of the initiative

636. The rules would specify the governance, funding, and operational details of the exchange, the trading and credit obligations on exchange participants, and processes the Commission would adopt for tendering the franchise to operate the exchange. As considerable detail is required to fully specify each of these aspects of the initiative, the discussion below outlines high-level issues that would need to be addressed.

Governance of the exchange

637. The Commission would need to decide whether it would have any governance oversight of the exchange, such as participation in exchange board meetings or the appointment of an independent party to monitor the exchange's credit situation. This would not be required for a voluntary exchange, but as the Commission would be requiring market participants to use the exchange to trade mandatory CfDs of significant financial value to them, the Commission's credibility, and the credibility of the initiative, would be damaged by financial failure of the exchange.

Funding of the exchange

638. The Commission would need to decide whether the exchange would be funded entirely from fees of exchange participants, or from levies on market participants, or from some combination of these options. Decisions on this issue would need to take into account whether the Commission intended the exchange to become self-sustaining in the medium term.

639. In regard to setting trading fees, the Commission needs to decide whether market-makers should be subsidised, and if so, by how much. Alternatively, the Commission can request that all responses to the tender include a proposal to address funding.

Operation of the exchange

640. The Commission would need to outline the operational aspects of the exchange prior to tendering so that bidders for operating the exchange can compete on a level playing field and provide a considered response. For example, the Commission would need to provide a framework for trading hours, the manner in which CfD trades occur, the pricing of traded CfDs, settlement and credit arrangements and reporting arrangements.

Trading obligations

641. The trading obligations on exchange participants would also need to be specified prior to franchising, as they will affect the operational costs of the successful franchisor. For example, trading rules would be required stating the manner in which participants are to submit bids and offers, the number of tranches, when and how bids and offers can be changed, when and how purchasers must respond to margin calls, and any other interaction with the exchange.

Contract details

642. The CfDs traded on the exchange would be the same as the CfDs currently traded on *EnergyHedge*, but with provision for CfDs to be referenced to monthly average prices at the Benmore, Haywards and Otahuhu nodes. Also, the contracts would be based on the model master agreements established under the initiative discussed in section 6.5.

Credit obligations

643. Robust credit obligations are a critical aspect of any exchange, as poorly administered arrangements can leave them susceptible to rapid financial failure. The Commission would need to decide the mark-to-market method upon which the exchange would make margin calls on exchange participants.

644. Industry experts who advised the HMDSG, suggested that there is a strong aversion within New Zealand companies to managing margin calls, and that participants are unlikely to have internal governance procedures in place to manage such requirements. The Commissions methodology would need to take account of these considerations when considering implementation.

645. Given the potential volatility of CfDs, the possibility of margin calls must be preserved. That does not mean that a flexible approach for those parties already posting prudential security in the electricity market could not also be considered.

Tendering processes

646. The tendering process would follow the same processes the Commission uses for selecting service providers for other functions. In addition, the Commission would need to request that respondents to the tender outline their commercials on a total cost basis (which the Commission would fund from a levy on market participants) or on a per transaction basis (in which case levies would not necessarily be required).

Monitoring and enforcement

647. Compliance with the obligation to trade standardised CfDs on the exchange would be monitored by the Commission, using information from the publication of contract details, as specified in section 6.3. The exchange would directly publish all exchange-traded CfDs in the manner specified by the publication of contract details initiative.

648. Exchange participants that fail to comply with the rules would be alleged to be in breach of the rules. The normal process for dealing with alleged breaches, as outlined in the Regulations, would then be followed.

Implementation

649. Implementing this initiative would require the Commission to develop new rules for the Minister’s approval. If the rationale for these rules is based on the view that

current market outcomes reflect the ‘chicken and egg’ nature of market dynamics, then the requirement to use a mandatory exchange would be self-sustaining once the exchange reaches a reasonable level of liquidity.

6.9.4 Potential benefits

650. The potential benefits of the initiative depend on whether introducing a mandatory exchange significantly reduces the costs of managing credit risks associated with trading standardised CfDs.

651. The analysis below assumes the exchange would bring significant credit risk management advantages relative to a situation in section 6.8 where standardised CfDs are mandatory but no exchange is provided for that trading. The analysis also assumes that it is uncertain whether these benefits are sufficient to exceed the costs of establishing and operating an exchange.

652. A majority of respondents in the UMR survey said a centralised trading platform that traded standardised derivatives would add liquidity and transparency to the risk management market. Follow up questions in the depth interviews showed that support for a centralised platform was conditional on whether the platform would realise competitive prices which in turn would influence how much volume was made available to that market. In the survey, of the 34 purchasers, 18 said their company would be interested in using a centralised platform, seven said they would not, and six were unsure.

653. The costs of organising bilateral credit arrangements was a reason for suggesting in section 6.8 that industrial consumers might demand less risk management cover as a result of mandatory trading of standardised CfDs. Introducing a mandatory exchange avoids this cost, and if the exchange’s fees are realistically priced then standardised CfDs should be attractive to risk management market participants.

Trading fees

654. The contract value and market maker risk mean that trading fees are not a primary consideration. Market participants have indicated that subsidised fees would not provide a significant incentive for increased trading levels on the exchange.

6.9.5 Costs and risks

655. The primary costs of the initiative relate to establishing and operating the exchange, and the risk that trading levels on the exchange may turn out to be too low to justify the investment. There are also risks the mandatory exchange initiative may foreclose opportunities for voluntary trading arrangements to develop further.

Rule development costs

656. Implementing this initiative would require the Commission to develop new rules for the Minister’s approval. One-off costs would be incurred to develop, consult, and finalise the rules, and a further one-off cost may be required if the rules require refinement at a later date. There would also be costs associated with legislative change.

Administration and compliance costs

657. The initiative would also impose regular ongoing costs imposed on buyers and sellers of CfDs to comply with the rules, and ongoing administrative costs for the

Commission in regard to paying for auditors and enforcing the rules via the Rulings Panel.

Tendering costs

658. Once the rules commence, the Commission would proceed to draft tender documents for franchising the exchange, issue the tender, receive bids, select the preferred supplier, and negotiate the service provider contract.

659. Bidders will also incur costs responding to the tender, and the preferred bidder will also incur negotiation costs. These costs are one-off in the first year of the regime.

660. The tender is likely to be repeated five years after the initial tender, and cost half the original amount as the original tender documents and processes will already be created.

Exchange set up costs

661. The successful bidder will incur management and IT development costs for establishing its exchange platform and business arrangements. For established exchanges, such as the Sydney Futures Exchange, the IT development costs would be minimal.

Exchange operating costs

662. The successful bidder will incur ongoing costs in managing the exchange business and continuing to develop the exchange platform.

Reduced incentives for innovation

663. The derivatives market in New Zealand is still in a formative stage, with ongoing development occurring in regard to contracting practices and contracting platforms.

664. Centrally designing the mandatory exchange under a rules-based approach is unlikely to provide an optimal framework for evolving the market as participants' needs evolve. For instance, considerable 'trial and error' will be required to see what works and what doesn't, making timely decision-making key to maximising the success of the venture. This may require independent and private governance arrangements, and appropriate commercial incentives to 'call the shots' when they are needed.

665. In addition, introducing a mandatory exchange at this stage is likely to foreclose opportunities for voluntary trading arrangements to develop on their own accord, such as broker bulletin boards and further development of *EnergyHedge*.

Lower quality information for policy making

666. This paper is proposing several initiatives that have the potential to achieve the benefits that the mandatory exchange initiative also seeks to achieve: more efficient risk management decision-making. Undertaking the mandatory exchange initiative now would foreclose opportunities for the Commission and other interested parties to observe how the other, less intrusive, initiatives affect the contracts market.

Demand risks

667. The primary risk associated with the initiative is that trading levels on the exchange may turn out to be too low to justify the costs of an exchange. The reasons for low trading levels may include, low liquidity, the standard CfD does not meet participants'

needs and they move to alternative risk management tools, FPVVs for example, or participants are left with residual exposure after trading a standard CfD.

Regulatory risks

668. As with other regulatory interventions, this initiative carries ‘regulatory creep’ risks. In particular, there is a risk that official support for the initiative will make it difficult for the exchange to be abolished if it fails as a commercial venture – rather, the presence of an official exchange could encourage officials to consider new regulations to stimulate trading volumes.

6.9.6 Conclusions

Timeframe for implementation

669. Implementing the initiative would take considerable time, in the order of 24 - 36 months following the commencement of the new rules. This amount of time is needed to specify and conduct the franchise tender, negotiate with the winning bidder, and allow time for it to develop and test the IT and complete its initial marketing activities.

670. The current provisions of the Act do not provide the Minister with authority to approve rules for the establishment of an exchange. Introducing this initiative, therefore, would require changes to the Act.

Certainty of net economic benefits

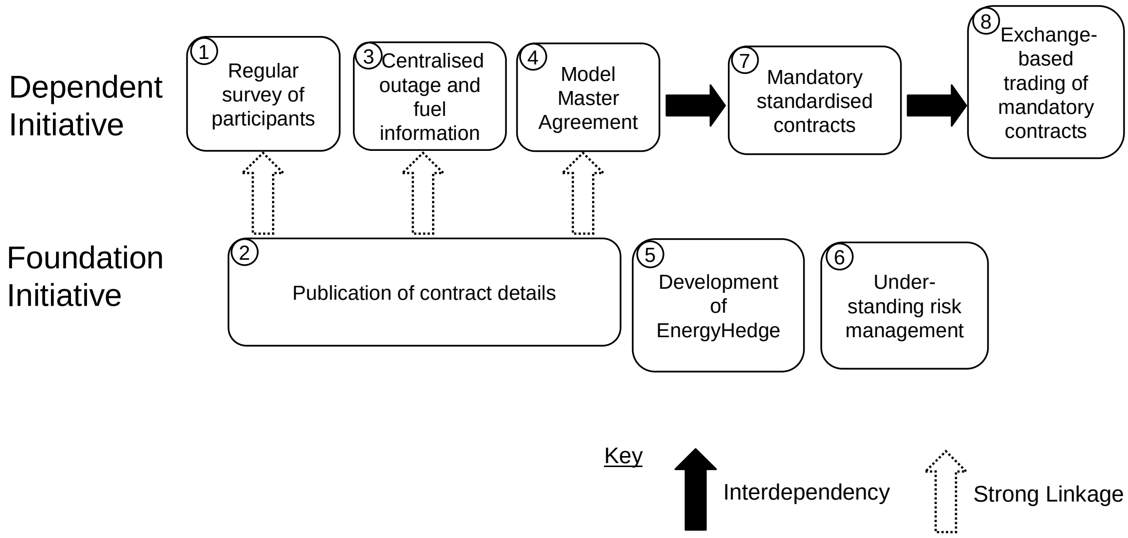
671. The net economic benefits of the mandatory exchange initiative are uncertain because of uncertainty about whether it reduces credit risk costs sufficiently to justify the costs of the regime. If trading volumes turn out to be low then the initiative is likely to produce net economic costs rather than net economic benefits.

672. Given these uncertainties, and the prospect of further development of *EnergyHedge* and increasing standardisation of contracts, the Commission has decided further consideration of mandatory exchanges should be deferred to allow evolution of the contracts market in response to the other initiatives recommended in this paper.

Overall conclusion

673. Mandatory use of exchange trading arrangements is a complex and radical initiative, which carries a high risk the designated exchange will discourage participation in the risk management market rather than achieve the intended (opposite) outcome. If uptake is low, the costs of operating the exchange for limited transaction volumes could be considerable.

Interdependencies and linkages



674. The introduction of a mandatory exchange requires standardised contracts and this interdependency is displayed in the diagram above. The transparent nature of exchange trading would deliver many of the benefits gained from the publication of contract details but through a more interventionist approach.

6.10 Synthetic separation of retail and generation

> ***Overview***
>
> *This initiative requires generator/retailers to supply a percentage of their internal hedge cover to blind derivative markets, to provide third parties with equal opportunity to acquire that hedge cover. Generator/retailers would be required to establish separate derivative trading teams for their generation and retailing businesses, and they would be prohibited from sharing information internally that could affect derivative prices. They would also be expected to publicly disclose all price-sensitive information that they wished to share with their affiliated business unit.*
>
> *The synthetic separation initiative is primarily directed at addressing purchaser concerns about generators supplying hedge cover on favourable terms to their own retail businesses and foreclosing the retail energy market to new entrants. The initiative also seeks to address purchaser concerns about limited availability of derivatives and low liquidity in the derivatives market.*
>
> *Overall, the net economic benefits of the initiative are highly uncertain. It is a reasonably complex and very intrusive intervention into the commercial operations of generator/retailers, which carries a high degree of risk of unintended and costly side effects. While liquidity in the derivatives market would probably increase, it is not clear that liquidity would be at more efficient levels, and there are other initiatives discussed earlier in the paper that potentially address that issue in ways that are more likely to be efficiency enhancing. Purchaser concerns about foreclosure of the retail electricity market would be addressed, but the initiative is unlikely to address their concerns about price discrimination.*
>
> *While the economic benefits are highly uncertain, the economic costs of the initiative are relatively certain as they arise primarily from the higher contracting costs from generator/retailers operating two derivatives trading desks, and also the costs of establishing and administering the synthetic separation regime.*
>
> *Given the highly uncertain benefits of the initiative and the commercial risks it may create for generator/retailers, the initiative does not warrant further consideration at this stage. Nevertheless, as it is one of the only initiatives that appears to address concerns about foreclosure of the retail market it would be prudent to hear from submitters on the issue.*

6.10.1 Introduction

675. Generator/retailers are *implicitly hedged* against spot price risks to the extent their generation and retail load levels are matched at nodes with similar price movements, and matched over time in terms of daily, weekly, monthly and seasonal profiles. The implicit hedge arises because, when the generation and retail businesses are closely matched, lower spot prices increase retail profits but reduce generation profits, and vice versa for higher spot prices.

676. “Synthetic separation” in this paper refers to arrangements requiring generator/retailers to supply a portion of this internal hedge cover to blind markets, to provide third parties with equal opportunity to acquire that hedge cover. Generator/retailers would be free to adopt integrated risk management policies and

strategies, but they would have to establish separate trading teams for their generation and retailing businesses, and they would be prohibited from sharing information internally that could affect prices in the risk management market. Generator/retailers would be expected to publicly disclose all price-sensitive information that they wished to share with their affiliated business unit.

677. This paper assumes other types of separation are out of scope, such as:

a. ownership separation - which would require generators and retailers to be owned by separate parties;

b. corporate separation - which would require generation and retailing businesses to be separately incorporated, and therefore separately managed and operated; and

c. business unit separation - which would allow generation and retailing businesses to be commonly owned and incorporated but would require separate business accounts and explicit transfer pricing arrangements.

678. Implementing the synthetic separation initiative would require the Commission to develop and administer new rules, and would require significant changes to the Act to empower the Minister to approve such rules.

679. In the rest of this section, the words “independent retailer” refers to retailers that are not owned or controlled by generators, and likewise the words “independent generator” refers to generators that are not owned or controlled by retailers. In regard to generator/retailers, the words “net generator” refers to parties that supply more generation than they take from the grid for the circumstance under discussion, and the words “net retailer” refers to the opposite case. The words “affiliated generators” and “affiliated retailers” are used when discussing one of the business units of a vertically integrated generator/retailer.

6.10.2 Promoters’ view

Key problems

680. Promoters of synthetic separation believe it would assist with addressing the lack of confidence about the competitiveness of the risk management market, a problem identified in section 3.3.3. In particular, they believe it would address competitiveness concerns discussed in section 2.4 regarding:

a. the availability of derivative contracts;

b. perceptions of market power;

c. vertical integration;

d. the lack of secondary trading; and

e. market transparency.

681. Promoters of synthetic separation believe it addresses these concerns by requiring generator/retailers to supply a portion of their internal hedge cover to blind derivatives markets. This not only increases the volume of contracts to the market, but also provides those contracts to all parties on the same terms and conditions.

Possible economic rationale

682. The economic rationale for synthetic separation rests on the view that a high degree of vertical integration may provide the most efficient means for incumbent generators

and retailers to manage risks, but it may also inhibit efficient entry to the generation and retail markets and/or exacerbate market power concerns. New Zealand's small market size, comprising a relatively small number of players, may intensify this situation. Moreover, a high level of vertical integration could inhibit the efficient evolution of a more liquid derivatives market because of the 'chicken and egg' nature of developing market liquidity.

683. Rather than lose the full efficiency benefits of vertical integration, or risk adopting a difficult-to-reverse structural solution, synthetic separation attempts to mimic a more vertically separated market by introducing contestability for a portion of the internal hedge cover between affiliated generators and retailers.

6.10.3 Specification of the initiative

684. The following specification is provided as an indication of the type of regime that would need to be developed to implement synthetic separation. Further analysis would be required to finalise the precise specification, which could change in material respects.

685. The following types of rules would be required to introduce synthetic separation:

a. *Participation requirements:* who would be required to comply with the regime;

b. *Volume requirements*: how synthetic separation levels would be determined for each participant;

c. *Trading requirements*: what contracts and trading arrangements would be required, including Chinese wall requirements;

d. *Administration arrangements*: how the regime would be administered, and how compliance would be monitored and enforced; and

e. *Implementation*: how the regime would be phased-in over time.

Participation requirements

686. Synthetic separation requirements would apply to vertically integrated and controlled generator/retailers, but not to any third parties, such as industrial consumers, or independent retailers and generators. In particular, the regime would not apply to industrial consumers with co-generation plants.

687. The synthetic separation regime would not apply to commonly owned but separately incorporated generator/retailers. For example, if the Government split its electricity generation and retailing businesses into separate State Owned Enterprises (SOEs) then there would be no need to apply synthetic separation to them as they would have appropriate incentives to contract for hedge cover through external markets. The same would apply to privately owned generator-retailers that split their generation and retailing into separate companies but retained common ownership via a holding company.

Volume requirements

688. In general terms, the volume of contracts that a generator/retailer would be required to supply to a blind market would be determined by calculating the generator-retailer's base volume of internal hedge cover, and multiplying the base by a percentage parameter. These factors are discussed in further detail below.

Determining the base

689. Ideally, the base for the synthetic separation regime should equal the volume of internal hedge cover owned by each generator/retailer. However, the amount of hedge cover provided by vertical integration varies, as it depends on the degree to which their generation and load volumes match over time and across nodes.

690. For example, a generator/retailer with base-load generation and flat load is better hedged than one with base-load generation and highly peaked load, or one with peak generation and flat load, or one with generation in Otago and load in the Bay of Plenty, or any combination of these factors.

691. For a net generator, the level of internal hedge cover equals the volume of affiliated retail load, assuming that the load perfectly matches the geographic and time profile of its generation. Although significant mismatches are likely in practice, the synthetic separation initiative assumes retail load provides a reasonable estimate of internal hedge cover for each net generator.

692. This assumption is predicated on the view that generators possess retailing businesses because of the risk management benefits the structure provides. Therefore, generator/retailers seek to acquire retail load with geographic and time profiles that offset the spot pricing risks associated with their generation assets.

693. The same approach is adopted for net retailers. In this case the total level of affiliated generation is assumed to provide a reasonable proxy for the level of internal hedge cover provided to each net retailer.

694. The base for the synthetic separation regime is therefore given by $min\{G,L\}$, where G and L denote estimates of generation and load, respectively, for each generator/retailer.

Mandatory contract volumes

695. The mandatory volume of contracts for a generator/retailer, M, would be set to a percentage, z, of the base:

$$M = z\% \times \min\{G,L\}$$

696. In other words:

a. *net generators* would be required to demonstrate that their affiliated retailers hold contracts *purchased* from blind markets or purchased from third parties exceeding a specified percentage of their retail load; and

b. *net retailers* would be required to demonstrate their affiliated generators hold contracts *sold* via blind markets or to third parties exceeding a specified percentage of their generation.

697. This initiative requires strict enforcement of the information sharing restrictions within vertically integrated organisations to ensure that all participants have equal access to CfDs.

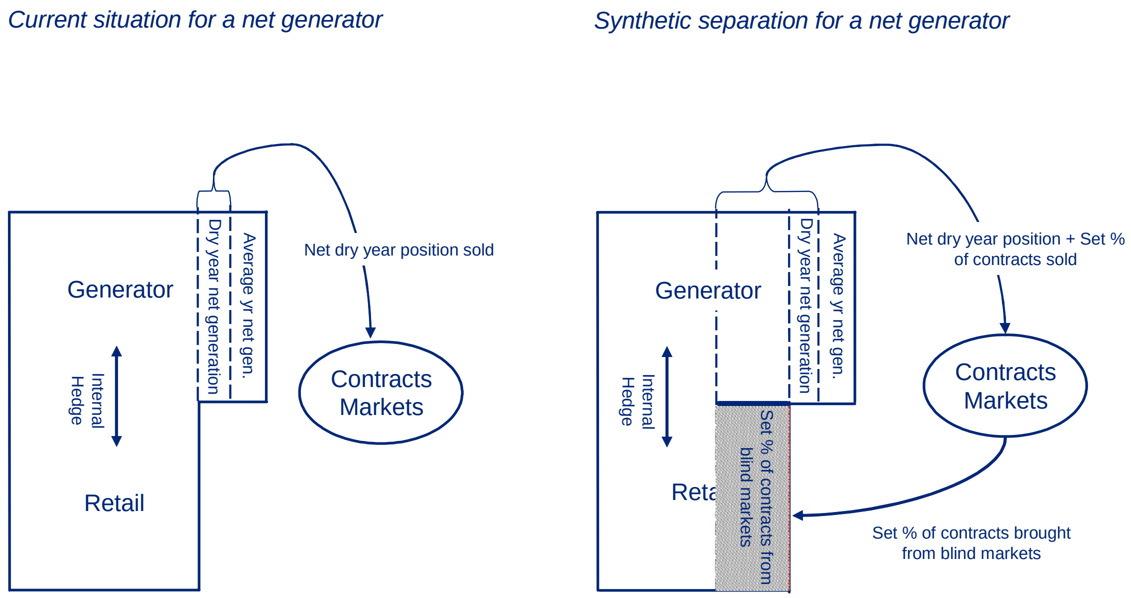
Illustration

698. The left-hand-side of Figure 17 illustrates the situation without synthetic separation. In this case we assume the generator/retailer is a net generator, and that its dry year generation levels exceed its retail load. We assume the net generator issues contracts to the risk management market equal to its dry year net generation level. As

the figure shows, the volume of contracts offered to the market by the net generator is a small fraction of its total dry year generation.

699. The right-hand-side of Figure 17 illustrates the synthetic separation initiative, where the net generator would be required to sell contracts equal to a percentage of its retail load, and thus greatly increasing the volume of contracts offered to the market.

Figure 17: How synthetic separation would work



700. The affiliated retailer would compete for contracts in the market, and is likely to obtain some contracts from its affiliated generator and the rest from other generators. If the net generator offers contracts that match the needs of its affiliated retailer particularly well, and if the retailer bids higher prices than its competitors, then it is possible the affiliated retailer could end up purchasing most of its contracts from its affiliated generator.

701. Note that if the net generator has little retail load relative to its dry year net generation levels, then it already has strong incentives to contract through the risk management market and so the synthetic separation regime imposes only a very small contracting requirement on it.

The percentage parameter, z

702. Given the intention of the synthetic separation initiative is to provide third parties with an equal opportunity to purchase a portion of the hedge cover received by vertically integrated retailers, it is not necessary to specify contracting levels equivalent to full synthetic separation. Rather, contracting requirements could be set at a moderate percentage of the base, 50 percent for example.

703. A moderate percentage parameter makes it likely that net generators with low levels of retail load will not be affected by the synthetic separation regime, as their contract volumes with third parties are likely to exceed the mandatory requirement. This is an acceptable outcome because the net generator is already contributing large contract volumes to the market. A moderate percentage parameter would mean that only highly integrated generator/retailers would be affected by the regime.

Estimating G and L

704. It is also not necessary to finely estimate generation and load levels, as only a portion of a generator/retailer's internal hedge cover is intended to be covered by the regime.

705. In regard to net generators, for example, it would be sufficient for them to forecast their retail load for the forthcoming 12 months based on historical load levels. This forecast would be reviewed and approved by an independent party. For example, retail load could be forecasted on a quarterly basis by:

a. using the previous 12 months' retail load for each net generator and adjusting it for one-off changes arising from the sale and purchase of customer blocks; and

b. applying the same rate of load growth to all retail load, to avoid making judgments about the future market shares of retailers. The quarterly approach, with one-off adjustments, avoids the base becoming too out of sync with future outcomes.

706. A similar approach could be adopted for estimating future generation for net retailers, although the higher level of generation variability will add some complexity. For example, the variability for wind/hydro generation, relative to a thermal plant, would need to be incorporated into any methodology. At the basic level, generation would be forecast for the forthcoming 12 months based on their generation over the previous five years, and adjust these figures for known one-off changes in capacity brought about by outages, purchases and sales of capacity, and investments and retirements of capacity.

Contract and trading requirements

Contract types

707. All types of derivatives would contribute to meeting the requirements of the mandatory level of contracting. Only FPVV contracts would be excluded from the regime, as they are not easily traded.

Trading arrangements

708. A key requirement of the synthetic separation regime is that contracts be publicly offered to all spot market purchasers, using blind trading arrangements where the seller does not know the identity of the bidders until after the trade is struck.

709. For example, generators wishing to conduct one-off public tenders could use brokers to achieve blind auction outcomes. Alternatively, a web-based auction platform could be used, provided it did not reveal bidder identities until after market closing, as occurs in the *EnergyHedge* market.

Credit arrangements

710. The blind nature of the trading arrangements would necessitate credit and/or prudential arrangements sufficient to satisfy the requirements of contract buyers and sellers. New rules may be needed to restrict generator/retailers from using credit and prudential requirements to disadvantage third parties. The exact nature of these rules will require a significant degree of consideration as solutions are not clear at this time.

Pricing arrangements

711. There would be no need to constrain the level of reserve prices offered to the derivatives market. Competitive pressure on reserve prices is assured by the blind

nature of the trading arrangements and the necessity for affiliated retailers to secure contracts from those markets to limit their generator's overall exposure to spot prices.

'Chinese wall' requirements

712. The synthetic separation regime requires generator/retailers to offer their internal hedge cover to third parties on an equal opportunity basis, and with equal access to price-sensitive information. To achieve this, the rules would need to specify requirements for generator/retailers to:

a. establish separate derivative trading teams for their retail and generation business units; and

b. prevent the two trading teams and their managers from communicating with each other regarding their day-to-day trading tactics and intentions. Insider trading type rules may be required to empower the authorities to investigate trades where it is suspected the two trading teams shared trading tactics and intentions or shared price-sensitive information without first disclosing to the public.

Administration arrangements

713. Compliance with the obligation to hold blindly traded contracts would be monitored by the Commission, using information from the publication of contract details, as specified in section 6.3. Enforcement would be relatively straightforward for this element of the regime.

714. Compliance with the Chinese wall and insider trading elements of the regime would be difficult to monitor and enforce. Ex-post auditing of contract bids and offers would need to be undertaken to detect possible rule breaches, and trading teams could be required to record all of their communications and make them available to investigators. The normal process for dealing with alleged rule breaches would be followed.

Implementation

715. The current provisions of the Act do not provide the Minister of Energy with the authority to approve rules for synthetic separation.

716. If changes to the Act were made, implementing this initiative would require the Commission to develop a suite of new rules for the Minister's approval. The Commission would also need to establish new forecasting arrangements, and check its results with affected parties. Generator/retailers would also need to establish separate trading teams.

717. As the mandatory contracting aspects of the initiative intrude fairly directly on the commercial operations of generator/retailers, there is considerable risk the initiative may alter contract market behaviour in unforeseen ways. There is likely to be value in the Commission phasing in the arrangements, for example, by starting the regime with blind contracting volumes at 10-20 percent of each base.

6.10.4 Potential benefits

718. The potential benefits of synthetic separation depend on views about whether concerns about price discrimination and foreclosure reflect misperceptions or reality, and how successfully synthetic separation affects those perceptions or reality. The analysis proceeds first on the basis that these concerns reflect perception rather than reality, and then considers benefits that arise if purchasers' perceptions are correct.

719. Synthetic separation may also achieve more efficient levels of contract availability and liquidity, which could have flow-on effects for efficient levels of vertical integration.

Case 1: misperceived concerns about price discrimination and foreclosure

720. On the basis that concerns about foreclosure are misperceived, synthetic separation would dispel those misperceptions and increase the confidence of prospective entrants to the New Zealand electricity market. If this occurred, it could bring economic benefits to New Zealand if new parties entered the retail or generation markets.

721. The analysis of price discrimination is more complicated. If price discrimination is not occurring, then synthetic separation should dispel any misperceptions that it is. This does not change anything of substance for purchasers, because generator/retailers will continue to offer them contracts at non-discriminatory prices, as is assumed now, but purchasers will have greater confidence that the price is fair.

Case 2: concerns about price discrimination and foreclosure are real

722. On the other hand, now assume that vertical integration allows generator/retailers to foreclose the retail market from new entrants and to price discriminate against industrial consumers.

723. If net generators are currently foreclosing the retail market, synthetic separation would make it difficult for them to continue to do so as the blind trading arrangements would mean generators would no longer know whether they are supplying contracts to their affiliated retailers or to other parties. The reverse is true for net retailers. The economic benefits in this case would come in the form of new entry or greater competitive pressure on incumbent generators and retailers.

724. The analysis of price discrimination is, once again, more complicated than foreclosure, in two respects:

a. First, even if net generators possess market power in the derivatives market, they will only price discriminate against industrial consumers if industrial consumers' demand for derivatives is less elastic than the generator's own internal hedge cover requirements. This is very unlikely because the retailing side of the generator/retailer business is generally highly sensitive to covering their expected level of retail load. One way to think about this is to conceptualise the affiliated retailer as an independent retailer. Relative to industrial consumers, the cost of electricity comprises a very large portion of their total costs, and so they are very sensitive to any gaps in their hedge cover. Industrial consumers are energy intensive relative to other consumers, but not relative to electricity retailers; and

b. Secondly, price discrimination can sometimes be efficient. If generator/retailers possess market power in the risk management market, then uniform pricing across all market segments leads to inefficient outcomes and price discrimination can reduce these inefficiencies by facilitating greater derivative contracting than would otherwise occur.

725. These considerations suggest that synthetic separation would bring little change in regard to price discrimination and deliver little economic benefit in regard to price discrimination concerns.

Concerns about contract availability

726. The synthetic separation initiative would almost certainly increase the volume of derivatives traded on the market, but it is not clear that this would be efficient.

727. Increased volumes arise directly from the requirements of the synthetic separation initiative. Moreover, the blind trading arrangements mean that retailers are likely to buy a portion of their contracts from non-affiliated generators, and generators will be contracting with non-affiliated retailers. This may create pressure for generator/retailers to trade standardised contracts to reduce contracting costs, and it may result in the development of more robust forward price curves.

728. Although synthetic separation could produce the above outcome, it may not provide more efficient outcomes. They are only more efficient if ‘chicken and egg’ problems, such as a low trading volumes resulting in low confidence in the market, exist.

729. At this stage it is very difficult to determine whether current trading levels are beset by ‘chicken and egg’ problems, or whether low trading volumes reflect a more fundamental lack of underlying demand for trading contracts.

Vertical separation of generator/retailers

730. Rather than subject themselves to the rigors of the synthetic separation regime, with Chinese walls and insider trading rules, generator/retailers may instead opt for corporate separation of their generation and retailing activities, particularly if the derivatives market develops greater depth and liquidity as a result of synthetic separation.

731. At the extreme, if synthetic separation created a very deep and liquid contracts market, such that independent generators and retailers obtained contracts on the same terms as generator/retailers, then the owners of generator/retailers could decide to concentrate on one side of the business and sell the other. As vertical separation would be chosen in this case, we can assume it is likely to be a more efficient outcome than synthetic separation. On the other hand, if the generator/retailers remain vertically integrated then that could also be an efficient outcome.

732. These effects are rather extreme and unlikely to occur, however, and are assumed to be negligible in our assessment of the net benefits of the synthetic separation initiative.

6.10.5 Costs and risks

733. The costs of synthetic separation depend on the extent to which synthetic separation inhibits generation/retailers from realising the efficiency benefits of vertical integration, and on the additional costs for generator/retailers to establish and operate separate trading teams. There are also costs arising from rule development, administration, and compliance activities, and synthetic separation may also introduce ‘regulatory creep’ risks.

Reduced efficiency benefits from vertical integration

734. A primary risk with synthetic separation is that it may inhibit generator/retailers from gaining the efficiency benefits of vertical integration. These benefits were outlined succinctly in the NERA Report, and can be summarised as follows[16]:

a. *More efficient risk sharing*. This occurs when affiliated generation and retailing businesses are well matched, so that spot price fluctuations cause offsetting fluctuations in profits for each business unit, leaving the profits of the combined entity less volatile than the profits of the individual entities; and

b. *Reduction in contracting problems*. Contracting problems occur when it is difficult to negotiate, write, or enforce "complete" contracts[17] and/or because information is not available to both contracting parties on an equal basis. In these situations, vertical integration offers advantages over explicit contracting.

735. Synthetic separation is quite different from ownership or corporate separation. Introducing synthetic separation in the manner specified in this paper would not forgo any of the above efficiency benefits of vertical integration because:

a. in regard to (a) above, derivatives also facilitate risk sharing, and indeed are likely to be as effective an instrument for doing so as vertical integration. Although synthetic separation may involve some additional transaction costs associated with buying and selling derivative contracts these could be lowered if more standardised derivatives developed in response to some of the initiatives outlined in this paper; and

b. in regard to (b) above, apart from the registration of master agreements, derivative contracts are generally easy to negotiate, write, and enforce. But unlike vertical integration, which can be characterised as a no-price variable-volume "contract", derivatives do not provide full cover against volume risk. Nevertheless, parties can adjust their derivative portfolio relatively easily, especially if the derivatives are standardised and in any case vertical integration doesn't provide full cover either, as it subjects the retailing business to mismatch risk and generator outage risks. Although using retail customers as a hedge is costly to serve and open to risk of customer switching, the market is currently showing very low levels of customer switching.

736. The implications of the claim in (a) are very important for determining the efficiency cost of synthetic separation, and are worth further discussion. Page 16 of the NERA Report discusses the cost of capital implications of vertical separation for generators, in regard to recent downgrades of (i) the debt ratings of generators without guaranteed outlets for their output and (ii) generators' long-term contracts with external counterparties.

737. As synthetic separation doesn't alter the retail base of generator/retailers, the debt ratings mentioned in (i) may not be affected. Although synthetic separation may increase contracting with external parties, much of this could be cross contracting with other generator/retailers, with potentially little effect on net credit risks. Further expert analysis and opinion should be obtained to draw firm conclusions regarding cost of capital effects.

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16 The NERA Report, at pages 15 and 16, also discusses two other benefits of vertical integration which are not particularly important for the discussion in this paper.

17 Complete contracts are contracts where each party's obligations can be clearly defined for all contingencies.

Undermining of property rights

738. Another risk is that synthetic separation may be perceived as unnecessary regulatory intervention which undermines existing property rights. Generators bought retail client bases because at the time they considered this to be an effective and efficient means to hedge their price risk exposure. Any attempt now to unwind these arrangements would be viewed by investors as a regulatory intervention that undermines the integrity of existing property rights. It is, therefore, likely to have a significant impact on the dynamic efficiency of the economy as a whole through discouraging investment and raising the returns required by investors to cover heightened concerns about opportunistic regulatory expropriation.

739. Although the synthetic separation could be applied only to SOEs, any move towards synthetic separation of SOEs is likely to lead to suspicion from investors that the same requirements could be applied to non-SOE companies.

Higher contracting costs

740. Relative to the baseline with vertical integration, synthetic separation requires generator/retailers to have two separate trading teams, housed in different areas of the business and with no cross over of personnel. Synthetic separation also requires greater investment in auction or tender arrangements, such as through brokers or web-based trading platforms.

Rule development costs

741. Implementing this initiative would require the Commission to develop new rules for the Minister’s approval. One-off costs would be incurred to develop, consult, and finalise the rules, and a further one-off cost would arise to refine them at a later date.

Administration and compliance costs

742. To implement these requirements, generator/retailers may need to hire additional staff and/or relocate existing staff.

743. The initiative would also involve ongoing administrative costs for the Commission in regard to forecasting base levels for setting the mandatory contracting requirements, paying for auditors to check compliance with Chinese wall and insider trading rules, and enforcing those rules via the Board and the Rulings Panel.

‘Regulatory creep’ risks

744. As with other regulatory interventions, this initiative carries ‘regulatory creep’ risks. In particular, there is a risk more stringent regulation will be adopted if the Chinese wall and insider trading rules are ineffective. There is also a risk that the relatively modest contracting requirements, initially set at 50 percent of the contract base, will be raised to higher levels to force greater contracting or to extend the maturity structure beyond one year.

6.10.6 Conclusions

Timeframe for implementation

745. Legislative changes to the Act could take 1 – 2 years to achieve (assuming there was sufficient Parliamentary support for it to occur). Once changes to the Act were made, it would take another 12 – 18 months to develop, consult on, and obtain the Minister’s approval for a suite of new rules. It would then take another 6 – 8 months to fully

implement the regime once the new rules commence, as the Commission would need to establish new arrangements for generators/retailers to provide their forecasts and have them independently assessed. Generator/retailers would also need to establish separate trading teams.

746. The overall timeframe for implementation is therefore about 2.5 – 3 years before the initiative could be fully implemented, although this timeframe could be reduced by about 1.5 – 2.5 years if the Commission developed new rules and processes in parallel with changing the Act.

Certainty of net economic benefits

747. The economic benefits of synthetic separation arise primarily in regard to whether it increases derivative market liquidity, and whether it addresses purchaser concerns about generator foreclosure of the retail electricity market. While both of these benefits are highly uncertain, the economic costs of the initiative are relatively certain as they arise primarily from the higher contracting costs from generator/retailers operating two trading desks and conducting blind auctions or tenders, and also the costs of establishing and administering the synthetic separation regime.

748. Some of the other initiatives discussed in this paper are intended to address the liquidity concerns that synthetic separation also seeks to address, but none of them address concerns about foreclosure. Concerns about price discrimination do not appear to be addressed by synthetic separation.

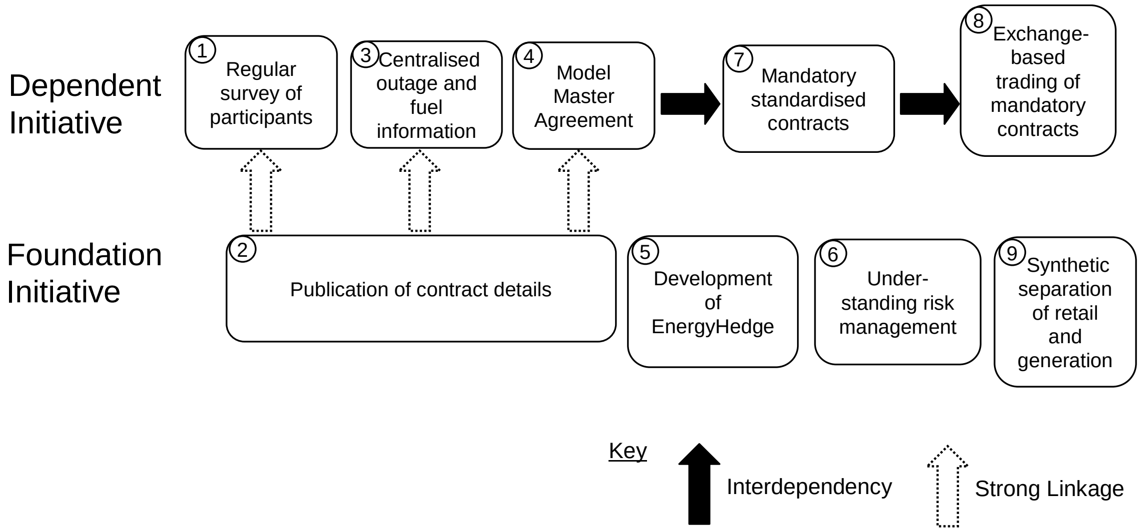
749. It is also important to acknowledge that synthetic separation is a reasonably complex and intrusive intervention in the commercial operations of generator/retailers. These actions carry a high risk of unintended and costly side effects, including dynamic efficiency effects for the country as a whole.

750. Although there could be significant benefits resulting from synthetic separation, the overall level of net economic benefits of the synthetic separation initiative are highly uncertain, at least relative to many of the other initiatives presented in this paper.

Overall conclusion

751. Given the highly uncertain benefits of the initiative and the commercial risks it may create for generation/retailers, the Commission has decided the initiative does not warrant further consideration at this stage.

Interdependencies and linkages



752. The synthetic separation initiative has linkages with other initiatives that seek to address liquidity concerns, particularly the initiative for development of EnergyHedge and also the mandatory standardised contracts initiative. These linkages are not strong, however, and unlike the other initiatives discussed in the paper so far, the synthetic separation initiative may affect retail market entry.

6.11 GPS mandatory offering requirements

Overview

This initiative requires generators to offer a minimum volume of contracts to the market, covering spot pricing risks over the year ahead. The offering volumes would be set as a percentage of forecast net generation levels, with provision for the Commission to make one-off adjustments to the offering requirements when estimates subsequently turn out to breach accuracy thresholds. Importantly, the initiative places no restriction on reserve prices in the offers and publication of reserve prices is not required.

The initiative appears to be directed at addressing Government concerns about a lack of transparency and liquidity in the derivatives market, and perhaps also concerns about security of supply co-ordination and market power.

The economic effects of the initiative are greatly affected by the details of the regime and, in particular, by generator freedom to set whatever reserve prices they wish. In effect, the initiative is a voluntary contracting regime. Nevertheless it leaves generators exposed to significant commercial risks. Its primary effect would be to require generators to maintain offer volumes during tight energy supply situations, such as during hydro shortages, but it is not obvious this would be beneficial to anyone. On the contrary, during the hydro shortages, it forces generators to defend hedge positions that are not in the best interest of security.

The initiative would require considerable rule development to implement, and considerable ongoing costs to administer and comply with. There may also be significant risks in terms of the implications for vertical integration, generation investment, and new entry to the generation market. Given that EnergyHedge already provides transparent pricing of derivatives, and the contract publication initiative would disclose the key details of all contract trades, the mandatory offering initiative appears very unlikely to deliver net economic benefits.

6.11.1 Introduction

753. The Act provides for the Minister to make regulations in regard to:

a. disclosure of information on hedge and contract volumes and prices;

b. requiring generators to post buy and sell prices for hedge (including futures) contracts;

c. *mandatory offering*: requiring generators to offer by tender a minimum volume of contracts that enable the price risks associated with the spot market to be managed, including the terms and conditions of those contracts (excluding prices and reserve prices); and

d. *mandatory purchasing*: requiring buyers of electricity from the wholesale market to maintain minimum levels of hedge and contract cover with electricity generators.

754. The above requirements are also replicated in paragraphs 71 and 77 of the GPS. Requirement ‘a’, above, is effectively covered by the initiative proposed in section 6.3 - Publication of contract details, and the *EnergyHedge* market established by

generator/retailers meets the second GPS requirement. This section considers the mandatory offering initiative, while the next section considers the mandatory purchasing initiative on its own and in combination with the mandatory offering initiative.

755. Implementing mandatory offering requirements would require the Commission to develop and administer new rules, and obtain the Minister's approval for them.

6.11.2 Promoter's view

Key problems

756. The mandatory offering initiative appears to be directed at addressing Government concerns about a lack of transparency and liquidity in the risk management market, and perhaps also concerns about security of supply co-ordination. For example:

- paragraph 76 of the GPS states that greater transparency and liquidity is necessary to enable market participants to manage their risks and to facilitate retail competition; and
- paragraph 71 of the GPS states the mandatory offering and purchasing initiatives are one of the possible options for dealing with concerns about security of supply co-ordination.

757. Although not explicitly mentioned in the GPS, the mandatory offering initiative appears also to be motivated by concerns about market power in the risk management market. A report from John Small in 2002[18] for the Ministry of Economic Development suggested there could be significant value in a compulsory hedging regime, but cautioned this view should be subject to further scrutiny. Paragraph 76 of the GPS appears to pick up these concerns with its statement that "Concerns are regularly expressed that the current hedge market does not operate particularly well".

Possible economic rationale

758. The economic rationale for the mandatory offering initiative depends on views about the underlying problem the initiative is seeking to address.

759. For example, if the initiative is intended to address lack of robust information, then the economic rationale rests on the view that there is a divergence between the public and private benefits of standing offers. It is normal commercial practice in many financial markets for traders to withdraw offers during extreme events, as internal governance delegations and processes set risk exposure limits for traders.

760. These private considerations generally do not take into account the wider public benefits that might arise from the provision of prices that inform 'market watchers' of market risks in terms meaningful to them. Market watchers would include not just spot market purchasers but also the media, consultants, advisors, government officials, and the government itself.

6.11.3 Specification of the initiative

761. The mandatory offering initiative discussed in this section differs substantially from the initiative in section 6.8, which considers mandatory requirements on parties to use a standardised CfDs for trading energy risk. Unlike the initiative in section 6.8, the

[18] Hedge Markets for Electric Power in New Zealand – March 2002

mandatory offering initiative doesn't require the offers to be for standardised contracts and there is no obligation on purchasers to buy them.

762. The rules for mandatory offering would need to specify:

a. *participation requirements*: who would be required to comply with the regime;

b. *volume requirements*: how mandatory offering levels would be determined for each participant;

c. *trading requirements*: what types of contracts and trading arrangements would be acceptable, and whether any restrictions would be placed on reserve prices;

d. *administration arrangements*: how the regime would be administered, and how compliance with the offering requirements would be monitored and enforced; and

e. *implementation*: how the regime would be phased-in over time.

763. As further detailed analysis is needed to determine the most effective and efficient specification, this section presents a preliminary specification to provide a basis for evaluating the initiative. Appendix E discusses specification options in further detail.

Participation requirements

764. A significant issue for a mandatory offering mechanism is whether the mandatory requirement should be based on a gross or net approach. The gross approach would mean generators would have to offer contracts equal to a percentage of their estimated future generation levels. The net approach means generators would only have to offer contracts equal to a percentage of their estimated future generation, less generation already hedged (including estimated future retail load and CfDs).

765. The specification in this paper assumes the net approach is adopted. All generators offering energy to the spot market would be required to meet mandatory offering obligations. Under the net approach of course, co-generation plants and net retailers would escape the mandatory offering requirements.

Volume requirements

766. The specification assumes the mandatory offering requirements would cover spot pricing risks over the forthcoming 18-month period. In particular, offering requirements would be based on forecasts of generation and load for 18 months ahead, as outlined below.

Offer volumes

767. Mandatory offer volumes, M, for each generator would be calculated as follows:

$$M = z\% \times (G - L) - C$$

Where G and L denote estimates of generation and load over the forthcoming year

z is a percentage parameter

C denotes the volume of energy over the forthcoming 18 months contracted to third parties.

768. This approach ensures mandatory offering requirements are zero for net retailers, and zero for net generators that have met their offering obligations via contracted outcomes.

Estimating future generation and load

769. Estimates of future load (L) for each net generator would be based on its average level over the last five years, adjusted for one-off changes in its retail base arising from the sale or purchase of blocks of customers.

770. Estimates of future generation levels (G) for each net generator would be based on its average level over the last five years, adjusted for one-off changes in generation arising from above normal outages, and from the acquisition, divestment, or retirement of plant. Generation from new capacity would be assumed to equal the average level of generation for that type of plant until a track record has been established.

771. This approach may impose offering obligations poorly related to the commercial position of each generator, which may place considerable pressure on the Commission to accept generator proposals for ad-hoc changes to estimated future net generation levels, or risk undermining industry support for the regime. To address these risks, the mandatory offering initiative would include a generic provision for the Commission to accept one-off changes to estimated net generation levels provided such adjustments are open to industry scrutiny before final decisions are made.

772. Appendix E discusses complications with alternative approaches to estimating future generation levels for each generator. This specification assumes the historical average approach is used rather than estimates of dry year generation as the latter approach is complex and produces results sensitive to modelling assumptions.

Contracts

773. Just as load reduces a net generator's hedging capacity at any one time, so do hedge contracts issued to third parties (C). Hence, almost any contract providing cover for spot price risk over the forthcoming 12 months would be included in C. The one exception to this rule would be where a net generator buys contracts from itself, as this would allow the net generator to scam the regime.

774. The volume of the contracts in C would be specified in terms of GWh units, so that contracts providing cover for only a portion of the forthcoming year would not be treated as equivalent to full-year contracts with the same MW capacity.

Illustration

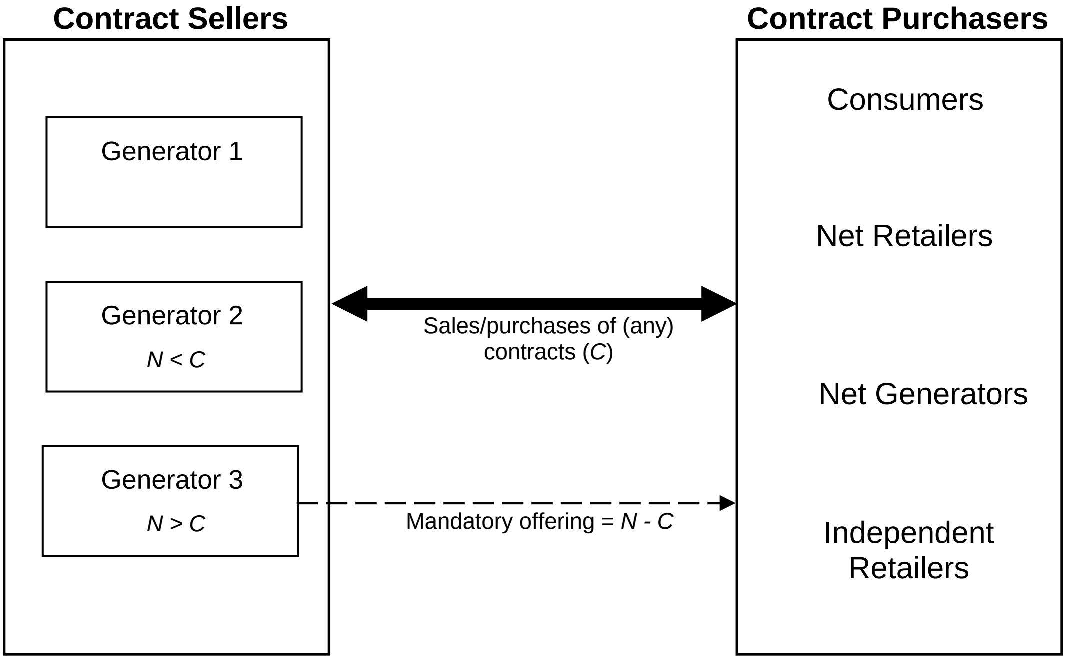
775. Figure 18 illustrates the mandatory offering initiative described above. The left-hand-side of the diagram shows net generators selling contracts, of varying maturities and other terms and conditions, to directly connected consumers, to net retailers, and to independent retailers (if any exist). Contract purchasers may also include net generators if they are looking to cross hedge. This activity occurs anyway, regardless of the presence of the mandatory offering requirements, although the volume of contracts could be influenced by the presence of the regime.

776. Contracts providing hedge cover over the forthcoming 12-month period satisfy the mandatory offering regime, and are denoted by C. It is convenient at this point to identify a notional offering requirement, N, defined as $N = z \text{ x } (G - L)$.

777. Generators with $N<C$ are not required to offer contracts as they have already offered contracts and struck deals with purchasers. This is the case for the top two generators on the left-hand-side of figure 18. For the third generator N exceeds C and so it would be required to offer additional contracts to the market, which are

represented by a dashed line with a single arrow to reflect the concept that mandatory offerings do not necessarily result in actual transactions.

Figure 18: The mandatory offering initiative



The timing of offers

778. Net generators, who haven't met their offering obligations, would be required to offer contracts, of volume M, to the market each business day. They would be required to offer the contracts at a specified time each day, and for a specified time period during the day.

Trading requirements

Eligible offers

779. One option would be to require net generators to offer standardised contracts, as the Act provides for the Commission to specify the terms and conditions of mandatory offerings. The standardised approach would be a very detailed and prescriptive approach, however, and would be similar to the initiative in section 7.7 on mandatory use of standardised contracts.

780. For the purposes of evaluating a mandatory offering initiative, this specification adopts a permissive approach where net generators would be free to offer whatever contracts they wished.

Reserve pricing restrictions

781. The minimum volume requirements underpinning this initiative mean net generators may, at times, be required to offer contracts when they do not want to. One way they could avoid transactions occurring would be to offer contracts at very high reserve prices.

782. Unless Parliament amends the Electricity Act 1992, the Minister does not have the power to introduce regulations setting reserve prices for electricity contracts, even if the Commission recommends such regulations. As the Act explicitly rules out regulations to set reserve prices, we assume the initiative would not contain any limits

on reserve prices and would not require publication of reserve prices. In economic terms, this renders the mandatory offering initiative a voluntary regime.

Tendering restrictions

783. The GPS and the Act provide for regulations that would require electricity generators to offer a minimum volume of contracts *by tender*, but neither document defines the word “tender”. This paper interprets the Act’s meaning to be; any public offer of eligible contracts that allows purchasers to submit bids on an equal basis.

784. There appears to be little value in requiring generators to offer contracts through any particular tender platform because modern information technology allows parties to access multiple platforms simultaneously. Provided the offering is public, with appropriate notice periods for purchasers to participate in it, then net generators should be free to adopt whatever offering platform best meets their needs.

Administration arrangements

785. To monitor generator compliance with their offering requirements, net generators would be required to provide information to the Commission on a quarterly basis. The Commission would provide a form for generators to complete, requesting information similar to that required by the initiative in section 6.3 for publishing contract details, but in this case the details would be in regard to contract offers. In addition, the form would request analysis on historical net generation levels, reserve prices, notice periods, offering method, response rate, and the volume of offers transacted.

786. Compliance with mandatory offering requirements would be monitored formally by the Commission, and informally by interested parties. Interested parties concerned about generator compliance with the rules would lodge rule breach allegations with the Commission. The normal process for dealing with alleged breaches, as outlined in the Regulations, would then be followed.

Implementation

787. Implementing this initiative would require the Commission to develop and administer new rules. The Commission would follow the normal rule-making process, and would periodically review the effectiveness of the new rules.

788. As mandatory offering rules involve a degree of complexity, particularly in regard to determining offering volumes, the arrangements should be phased in over a period of time. For example, offer volumes could start at 75 percent of net generation and increase to a maximum of 90 – 100 percent over a three to five year period.

789. Although these percentage parameter values are very high, the Commission’s 2005 hedge market survey revealed that 75 – 80 percent of the net load of electricity purchasers participating in the survey was covered by hedges in 2005 and 2006. Given these figures, adopting a lower percentage parameter would likely mean the initiative would have had no effect on offers to the market.

6.11.4 Potential benefits

790. The potential benefits of the mandatory offering initiative relate primarily to its potential impact on the transparency and liquidity of the risk management market. It is difficult to identify security of supply benefits or any constraints on the exercise of market power in the risk management market (if any market power exists).

Transparency and liquidity during times of extremes

791. A possible benefit of the initiative arises from the effect it may have on the risk management market during extreme supply shortages, such as temporary hydro shortages. The mandatory offering initiative would require net generators, who have not met their mandatory offering obligations, to offer contracts during extreme events, whereas currently they often withdraw from the market under current arrangements due to board policies on trading limits.

792. As the initiative doesn't require generators to publish reserve prices, there would appear to be little gain in transparency. Even if publication of reserve prices was required, such prices reflect the views of only one side of the market, and are likely to be highly subjective and volatile during the crisis period.

793. In regard to liquidity, it may be argued that there is limited value in requiring generators to offer contracts during supply crises, as purchasers derive little value from obtaining hedge cover in the middle of a crisis. Although there is some truth in this reasoning, purchasers may hold a different view to generators regarding the extent of the supply problem and consider that high price hedge cover is appropriate to protect against an escalation of the supply crises. This decision could be the difference between a reduced profit and a bankruptcy and it seems appropriate to require generators to offer contracts.

794. In the absence of the ability to set reserve prices, this initiative may introduce a distortion by creating the impression that supply contracts are available when, in reality, the generators have set a reserve price that ensures the contract will not be struck.

Transparency and liquidity during normal conditions

795. It is difficult to see how the initiative increases the transparency and liquidity of the risk management market during normal conditions. There would appear to be little positive impact on transparency as the mandatory offering initiative does not require publication of reserve prices or the offering of standardised contracts. In any case, if the contract publication initiative in section 6.3 is adopted then transparency regarding prices and volume would be achieved anyway.

796. In regard to liquidity, mandatory offering is just a requirement to offer contracts, and does not in itself require anyone to trade contracts. Additional liquidity requires increased trading and/or reduced bid-offer spreads, neither of which appears likely as a result of an offering requirement.

Other potential benefits

797. The GPS indicated that security of supply co-ordination could be another benefit of mandatory offering requirements, but again this seems highly unlikely because there is no limit on reserve prices and no requirement to contract. Likewise, any suggestion the initiative would constrain market power, if it exists, seems unlikely given that net generators can set whatever reserve price they wish.

6.11.5 Costs and risks

798. Although the mandatory offering initiative appears to carry significant commercial risks for net generators, their ability to set high reserve prices enables them to circumvent any risk. There is a risk that this may encourage 'regulatory creep' as a mechanism to control reserve price is investigated and this could seriously harm investment, innovation, and ongoing evolution of the risk management market. Any

amendments in this area could also discourage generation investment, and new entry into the generation market, and it would impose compliance costs on net generators and administration costs on the Commission.

Commercial risks and fairness

799. The mandatory offering requirements should, in theory, be based on estimates of dry year generation for hydro generators, but doing so is likely to be complex and expose the regime to sensitive modelling assumptions (these issues are discussed further in Appendix E). The specification in section 6.11.2, therefore, assumes the mandatory offering requirements would be calculated on the basis of historical average generation levels, with one-off adjustments for discrete changes in generation capacity and load levels, and ad-hoc adjustments approved by the Commission.

800. Despite the provision for ad-hoc adjustments, the mandatory offering initiative carries significant commercial risk for generators without balanced portfolios or without force majeure clauses. For example, generators with predominantly hydro sources of generation could be required to offer contracts exceeding their net generation levels during dry years. Similar comments apply in regard to wind generators. If purchasers accepted these contracts then these generators could become over-hedged, leaving them either exposed to spot market prices or having to cross-hedge with other generators.

801. These risks could be minimised by setting a low percentage parameter, z, but this would render the regime redundant if it is set too low, as the 2005 hedge market survey shows that generators are relatively highly hedged anyway. Alternatively the percentage parameter could be set too high, in which case the regime potentially creates winners and losers, as discussed above.

'Regulatory creep' risks

802. Introducing the mandatory offering initiative would bring the risk management market one step away from officials setting reserve prices or setting the volume of hedge cover generators would be required to hold. As there would be significant difficulties with accurately estimating future net generation levels, the scheme is likely to fail, which in turn could lead to more intrusive interventions. These concerns would be likely to reduce investment in the electricity sector and undermine evolution and innovation in the risk management market.

Inefficient levels of vertical integration

803. The specification assumes mandatory offering requirements would be based on net generation levels. If net generators view the mandatory offering initiative as onerous or intrusive, the regime could encourage them to increase their degree of vertical integration. At the extreme, the initiative could encourage net generators to become net retailers to avoid the regime altogether. These outcomes would be unlikely to be efficient as they would stifle further development of the risk management market.

Inefficient investment and new entry

804. Similar concerns arise in regard to generation investment and new entry to the generation market. If the mandatory offering initiative is viewed as an onerous or intrusive regime, it could discourage net generators from building new generation capacity to minimise their mandatory offering obligations. Likewise, new entrants to the generation sector could be discouraged by a regime that imposes offering obligations on them.

Administration and compliance costs

805. Implementing the initiative would require complicated rules to determine mandatory offering requirements for new entrants or for large step changes in generation capacities. The rules would also need to define very clearly the circumstances in which the Commission could make ad-hoc adjustments to the mandatory offering requirements to address the commercial risks discussed above.

806. Implementing the initiative would require one-off costs associated with developing the rules, and further costs to refine them over time as experience is gained with them.

807. The initiative would also impose some ongoing administration costs on the Commission, to review and approve monthly forecasts of net generation levels, to collate and interpret information provided to it about current contract volumes, to work with affected parties to resolve any queries that might arise from the forecasting calculations, and to formally notify net generators of their obligations.

808. Net generators would incur ongoing compliance costs, to provide information to the Commission, to check the Commission's calculations, and to monitor compliance with its obligations. Net generators would also incur ongoing costs of offering contracts in the market, and operating credit arrangements to match the risks associated with standardised contracts.

6.11.6 Conclusions

Timeframe for implementation

809. If the Commission decided to adopt this initiative, it would need to formulate rules specifying the information net generators are to provide to the Commission, the formula and processes for calculating and finalising offer volumes, and the treatment of contracts in the offer formula. Generators would need to determine the method by which they would make their offers available to the market, the processes they would adopt to inform market participants of their offers, and the processes for collecting, checking, and forwarding data to the Commission.

810. Many of these tasks could be developed in parallel. The rules would probably take 12 – 18 months to prepare and another six months to consult on and provide recommendations to the Minister of Energy. New rules could therefore be implemented within a 1.5 – 2 year timeframe, with six months for the Commission and generators to trial the arrangements before formally commencing the initiative. The overall timeframe for implementation is therefore in the order of two – three years.

Certainty of net economic benefits

811. The economic effects of the initiative are greatly affected by the details of the regime and, in particular, by generator freedom to set whatever reserve prices they wish. In effect, the mandatory offering initiative is a voluntary contracting regime because generators can set an extremely high reserve price if they do not wish to trade a hedge contract. Nevertheless, it leaves generators exposed to significant commercial risks. Its primary effect would be to require generators to maintain offer volumes during tight energy supply situations, such as during hydro shortages, but it is not obvious this would be beneficial to anyone. On the contrary, such a requirement may create a false impression of abundant supply during a period of shortage.

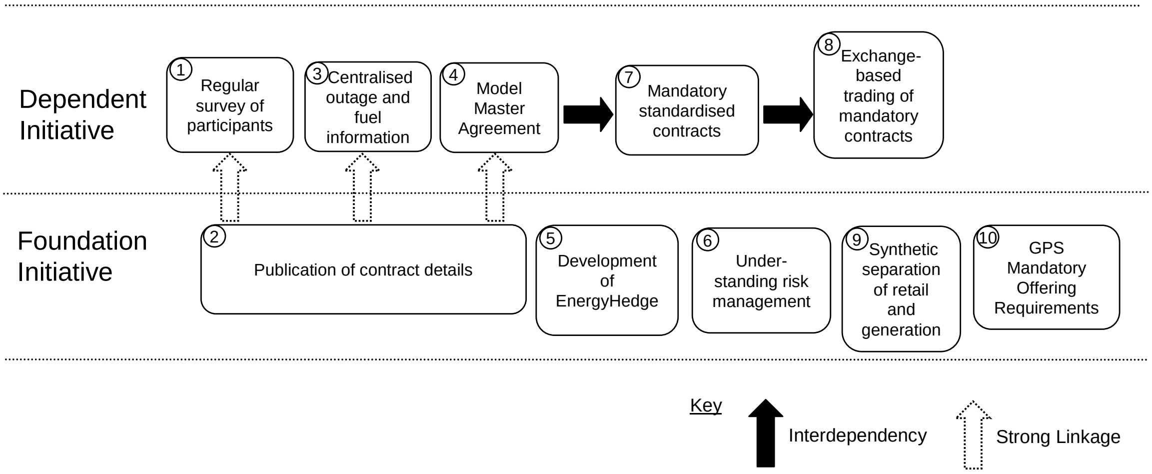
812. The mandatory offering initiative requires considerable rule development to implement, and considerable ongoing costs to administer and comply with. There may also be significant risks in terms of the implications for vertical integration,

generation investment, and new entry to the generation market. Given that *EnergyHedge* already provides some price transparency for derivatives, and the contract publication initiative discloses the key details of all contract trades, the mandatory offering initiative appears very unlikely to deliver net economic benefits.

Overall conclusion

813. Given the limited benefit effects the initiative would have on risk management market outcomes, the complexity evident in even the simplest specification, and the significant commercial risks it would create for generators, the Commission has decided the initiative does not warrant further consideration.

Figure 19: Interdependencies and linkages



814. The mandatory offering initiative has only a weak linkage with the publication of contract details and the mandatory standardised contracts initiatives. Both initiatives increase market transparency, but little transparency of prices would be obtained from the mandatory offering initiative.

6.12 GPS mandatory purchasing requirements

Overview

This initiative requires spot market purchasers to maintain a minimum level of hedge and contract cover, covering spot pricing risks over the year ahead. In contrast to the mandatory offering initiative, this initiative requires parties to actually purchase risk management contracts rather than offer to purchase them. Nevertheless, the initiative appears to be driven by the same Government concerns mentioned about the mandatory offering initiative, viz: concerns about lack of transparency and liquidity in the derivatives market.

Although in theory, the mandatory purchasing initiative could be used to spur the more efficient risk management outcomes; this is very unlikely to occur in practice. Rather, the mandatory purchasing initiative is highly likely to create large economic costs as it imposes a 'one size fits all' approach to risk management on all parties exposed to spot prices, who actually have diverse interests and risk management needs. The initiative is also likely to seriously damage incentives for efficient innovation, and carries serious regulatory risks.

There would appear to be relatively high risks of unsuccessful implementation of the initiative because of the risks associated with setting mandatory volumes and financial penalties too low or too high.

These difficulties, along with the adverse outcomes for vertical integration and retail competition, suggest that the mandatory purchasing initiative is likely to impose net economic costs on New Zealand. This conclusion is further supported by the prospect the initiative may expose spot market purchasers to extremely high contract prices, which would likely result in abolition of the regime.

Clearly, the mandatory purchasing initiative intrudes directly on spot market purchasers' contractual relationships. In principle, there should be compelling evidence of market failures and compelling arguments in favour of the initiative before highly intrusive interventions of this nature are adopted. If less intrusive initiatives are available then it would be prudent to pursue them before considering the mandatory purchasing initiative.

6.12.1 Introduction

815. The previous section considered the GPS requirement for the Commission to consider introducing mandatory *offering* requirements on generators. This section considers the regulatory making power related to hedges in the GPS, which is for wholesale market purchasers to *maintain* a minimum level of hedge and contract cover with electricity generators. As for the mandatory offering initiative, implementing the mandatory purchasing initiative would require the Commission to develop and administer new rules, and obtain the Minister's approval for them.

816. The mandatory purchasing initiative carries some similarities with the mandatory offering initiative discussed in the previous section. To minimise duplication, section 6.12 focuses on the key areas of difference with the mandatory offering initiative and section 6.12.6 discusses how a combined mandatory offering and purchasing initiative would affect the evaluation of net economic benefits.

6.12.2 Promoter's view

Key problems

817. The mandatory purchasing initiative appears to be motivated by some of the same concerns as the mandatory offering initiative, as the GPS refers to greater transparency and liquidity, and retail competition, in regard to both initiatives.

Possible economic rationale

818. The economic rationale for the mandatory purchasing initiative appears to arise from concerns that spot market purchasers can access "political insurance" to mitigate spot pricing risks, and so face weak commercial incentives to use derivatives. The rationale may also be based on views that derivative markets suffer 'chicken and egg' problems: with limited liquidity, few parties want to participate in the market, leaving the market illiquid, which undermines commercial incentives to participate, and so on. The mandatory purchasing initiative seeks to address these concerns by requiring spot market purchasers to hold minimum levels of hedge cover.

6.12.3 Specification of the initiative

819. The mandatory purchasing initiative requires many of the same specifications as the mandatory offering initiative, covering:

   a. participation requirements;

   b. volume requirements; and

   c. other requirements, such as administration and implementation arrangements.

820. As with the mandatory offering initiative, this section presents a preliminary specification of the mandatory purchasing initiative to provide a basis for evaluating the initiative.

Participation requirements

821. The GPS and the Act refer to "buyers of electricity from the wholesale market" being required to maintain minimum levels of hedge and contract cover. The reference to the wholesale market is not clear, as it could include anyone exposed to spot price risk.

822. As New Zealand operates a 'gross pool' for the spot market, it would be feasible to focus the initiative narrowly on spot market purchasers – that is, to directly connected consumers buying from the spot market, to generator/retailers, and also to independent retailers. This paper assumes the narrow approach was the intention in the GPS and in the Act.

823. The specification for the mandatory offering initiative assumed offering requirements were based on net rather than gross generation levels. As the GPS refers to hedge cover, not just contract cover, it is assumed that generation owned by spot market purchasers would count towards meeting the requirements of this initiative.

Volume requirements

824. This specification assumes the hedge and contract cover is required to cover spot pricing risks over the forthcoming 12-month period. The mandatory volume of hedge cover for each spot market purchaser would be determined very simply by:

$$M = z\% \times L$$

Where M denotes the volume of mandatory hedge cover, L denotes load over the forthcoming year, and z is a percentage parameter. Note, M is the volume a spot market purchaser must buy, irrespective of the price set by generators.

825. Any type of hedge contract and self-generation arrangement would be considered as meeting the hedge cover requirements. As most spot market purchasers ordinarily possess hedge contracts (C) or own generation (G), the additional hedge cover required by the above regime is given by $max[0 , M - G - C]$. This means that net generators would not be caught by the mandatory purchasing regime. Similarly, spot market purchasers that ordinarily contract more than z percent of their annual load will not be directly affected by the mandatory purchasing initiative. There may be some indirect impact if the proposed regime increases hedge prices.

Estimating future generation and load

826. The same estimation issues arise under the mandatory purchasing initiative as for the mandatory offering initiative.

Other requirements

827. The administration and implementation issues are largely the same as for the mandatory offering initiative.

6.12.4 Potential benefits

828. The potential benefits of the initiative depend critically on one's views about spot market purchaser incentives to manage risks using commercial risk management methods. The following analysis considers two cases: spot market purchasers' incentives are undermined by their ability to access "political insurance" (case 1); and spot market purchasers' incentives to use derivative instruments are weak due to coordination problems (case 2).

Case 1: political insurance

829. In this case, the potential benefits of the initiative would be positive if the political insurance problem led to under insurance by parties exposed to spot price risks. In practice this seems highly unlikely, given that the UMR survey showed that consumers typically hedge around 75 – 80 percent of their load.

830. Although an 80 percent level may or may not fall short of the theoretically optimal level of hedge cover, there is currently no empirical evidence available to inform such a view. The optimal level of cover will vary for each risk management market participant, and so implementing a 'one size fits all' regime at levels above 80 percent is highly likely to force some parties to acquire inefficient levels of hedge cover. This potential inefficiency is a potential cost, and is discussed further in section 7.12.5.

Case 2: coordination problems

831. The mandatory purchasing initiative could stimulate greater derivative trading, as parties holding insufficient contracts seek to acquire derivatives from parties with surplus contracts, to avoid incurring financial penalties from breaching their mandatory purchasing obligations.

832. In theory this could spur the market to more efficient liquidity levels if current liquidity levels are inefficient due to coordination (i.e., ‘chicken and egg’) problems. In practice, there is no reason to believe that trading activity driven by penalty avoidance would provide a significant or sustainable spur to market liquidity. For example, a penalty avoidance approach implies that market participants would hold on to their surplus contracts if they are uncertain about being able to readily obtain contracts when they need them.

6.12.5 Costs and risks

833. The mandatory purchasing initiative would expose spot market purchasers to serious commercial risks, carries significant regulatory risks, and would seriously distort innovation in the risk management. It would impose onerous compliance costs on spot market purchasers, and encourage inefficient behaviour in the risk management and spot markets.

Commercial risks

834. The mandatory purchasing initiative is likely to be very intrusive in the commercial operations of all spot market purchasers.

835. In particular, a key issue with the mandatory purchasing initiative is that it exposes spot market purchasers to the risk of having to purchase contracts at extremely high prices. One way to consider this situation is that the mandatory purchasing requirement reduces the price elasticity of demand for hedge contracts. The more onerous the penalties for breaching the requirement the more inelastic the demand curve. Since, typically, at some point, electricity supply also becomes quite inelastic in the short-term; the potential impact of the requirement to purchase contracts at high prices could be very extreme. This initiative can be thought of as providing significant extra leverage to any market power that generators may have already.

836. While participants may be able to manage this risk by purchasing contracts well in advance of the mandatory requirement when prices are reasonable, there nevertheless remains the risk that spot prices rise precipitously and catch out spot market purchasers needing to purchase contracts to meet their mandatory requirements.

837. This initiative would require an explicit set of measures that would result in a more intrusive enforcement mechanism than adopted for other rule breaches.

Regulatory risks

838. The mandatory purchasing initiative carries serious ‘regulatory creep’ risks, as it would create strong incentives for future regulators to introduce price caps to address generator market power arising from the captive market available to them. The cap would probably be only on some trades and applicable in some circumstances, but pressures would grow for extending it to a wider range of trades as risk management participants take action to avoid it. At the extreme, the mandatory purchasing initiative could lead to a fully administered electricity market, with no spot market pricing.

Inefficient innovation

839. The mandatory purchasing initiative is likely to seriously constrain the ability of market participants to evolve the risk management market over time, and to innovate with new products and new trading platforms. Instead, it would create strong incentives for risk management participants to innovate in ways designed to undermine the

mandatory hedge requirements. The dynamic inefficiency costs of misdirected innovation are likely to be very large over time.

Administration and compliance costs

840. The administration and implementation costs are likely to be as onerous as for the mandatory offering initiative.

841. The mandatory purchasing initiative is likely to involve higher compliance costs than the mandatory offering initiative. For example, spot market purchasers would incur ongoing costs of purchasing contracts additional to their requirements under the baseline case. Also, to minimise the risk of incurring financial penalties for breaching their obligations, spot market purchasers could incur significant costs monitoring their obligations and closely controlling their contract levels.

Less efficient physical market outcomes

842. The mandatory purchasing initiative imposes hedge obligations on spot market purchasers. If these obligations exceed the level of hedge cover spot market purchasers wish to hold, then they have incentives to avoid the obligation when avoidance costs are less than obligation costs.

843. For example, spot market purchasers may seek to avoid mandatory purchasing obligations by withdrawing from the spot market. A large consumer could choose to exit the spot market and purchase electricity from a retailer with a tariff based on spot market prices.

844. For similar reasons, the mandatory purchasing initiative may also deter new entry to the retail market. For example, the mandatory purchasing initiative may discourage independent generators from entering the retail market, to avoid the risks and costs of the regime. For independent retailers, the mandatory purchasing initiative would compel them to purchase contracts from competing generator-retailers or breach their mandatory obligations. This approach may well deter independent retailers from entering the retail market.

Less efficient risk management outcomes

845. The mandatory requirement on spot market purchasers to obtain hedges may create a captive market for net generators to sell hedges, allowing them to collectively exercise market power. For example, generators may be able to withhold contracts from the market (i.e., set high reserve prices) as they know purchasers risk breaching their purchasing obligations if they don’t purchase contracts. The higher the financial penalties the greater the collective market power potentially available to generators.

846. More generally, the mandatory purchasing initiative may encourage greater vertical integration of generator/retailers, with net retailers buying generation to reduce their exposure to mandatory purchasing obligations. Consumers could also be encouraged to acquire generation plants when it is inefficient for them to do so.

847. The mandatory purchasing initiative may also create inefficient risk management outcomes by requiring all spot market purchasers to hedge to a specified level, such as 90 percent of gross load. This ‘one size fits all’ approach is likely to hedge some purchasers above their efficient level. At the extreme, for example, the efficient approach for purchasers with ‘deep pockets’ may be to not hedge at all but rather to allow their cash position to fluctuate with fluctuations in their energy costs. The mandatory purchasing initiative does not allow for these variations in consumer needs.

848. The mandatory purchasing initiative may also encourage an inefficient level of contract trading. Although the mandatory purchasing initiative could spur the risk management market to become deeper and more liquid, it could also encourage too much derivative trading because trading volumes would be driven by parties trading to avoid financial penalties.

6.12.6 Conclusions

Timeframe for implementation

849. The timeframe for implementing the mandatory purchasing initiative would be similar to the timeframe for the mandatory offering initiative, taking about two – three years.

Certainty of net economic benefits

850. Although in theory the mandatory purchasing initiative could be used to spur more efficient risk management outcomes, this is very unlikely to occur in practice. Rather, the mandatory purchasing initiative is likely to create large economic costs as it imposes a ‘one size fits all’ approach to risk management on all parties exposed to spot prices, who have diverse interests and risk management needs. The initiative is also likely to seriously damage incentives for efficient innovation, and carries serious regulatory risks.

851. These difficulties, along with the adverse outcomes for vertical integration and retail competition, suggest that the mandatory purchasing initiative is likely to impose net economic costs on New Zealand. This conclusion is further supported by the prospect the initiative may expose spot market purchasers to extremely high risk management prices, which would likely result in the abolition of the regime.

Implementing both mandatory offering and purchasing initiatives

852. Implementing both initiatives is unlikely to substantially alter the net economic benefits of the initiatives. The primary advantage of implementing both initiatives is that the adverse consequences for vertical integration under each initiative would tend to cancel out. For example, incentives to acquire retail load under the mandatory offering initiative would tend to offset the incentives in the mandatory purchasing for parties to acquire generation.

853. The combination of initiatives also means that purchasers will be less exposed to the captive market, described earlier in this section, but the ability of generators to set reserve prices still leaves them at a disadvantage.

854. Another advantage of implementing both initiatives appears to be that it would improve incentives for generator/retailers to accurately estimate their future generation and load. For example, seeking to reduce mandatory offering obligations by under-estimating future generation levels would simply result in higher mandatory purchasing obligations on them. Likewise, under-estimating future load to reduce mandatory purchasing obligations would increase their mandatory offering obligations.

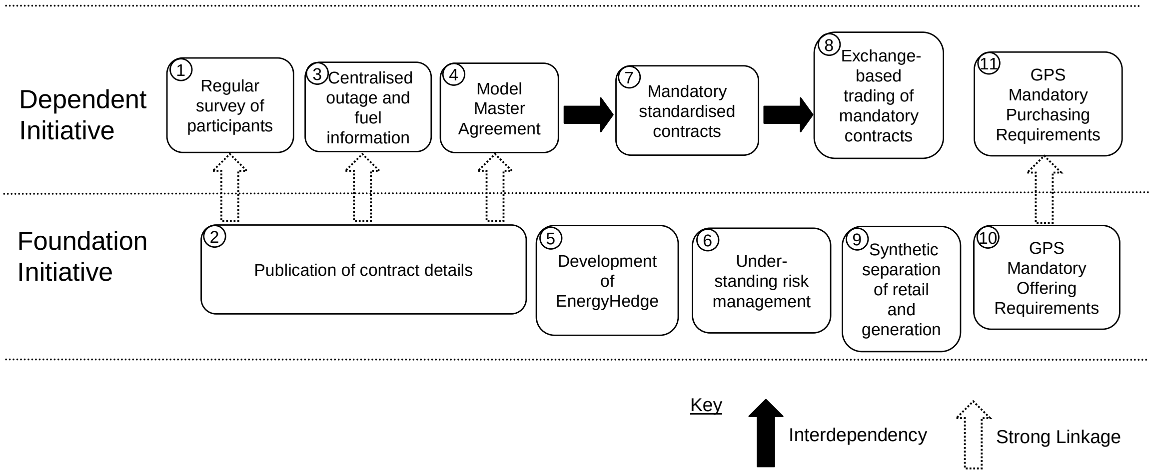
855. These advantages of jointly implementing both initiatives are minor, and do not reverse the overall assessment that both initiatives are likely to create large net economic costs rather than net economic benefits.

Overall conclusion

856. Clearly, the mandatory purchasing initiative intrudes directly on spot market purchasers' commercial risk management relationships. In principle, there should be compelling evidence of market failures and compelling arguments in favour of the initiative before highly intrusive interventions of this nature are considered. If less intrusive initiatives are available then it is generally prudent to pursue them before considering the mandatory purchasing initiative.

857. As other, less intrusive, initiatives are available, the Commission has decided the mandatory purchasing initiative does not warrant further consideration.

Figure 19: Interdependencies and linkages



858. The mandatory offering initiative is strongly linked with the mandatory purchasing initiative, in that they are both motivated by Government concern about the transparency and liquidity of the risk management market.

7 TRANSMISSION RISK MANAGEMENT INITIATIVES

859. The previous section considered initiatives for improving electricity risk management generally, and focused in particular on *energy price risk*. However, energy price risk is only one component of the risk parties face if they purchase or sell electricity on the spot market. The other component is *locational price risk*, which arises because the spot market produces different prices across the country to reflect losses and constraints on the transmission system. This section considers initiatives directed at improving the management of locational price risk – called “transmission risk management initiatives” in this paper.

860. Currently locational price risk is managed by spot market purchasers buying CfDs from generators at specific locations, and by generator/retailers owning generation plant in the same region in which they have retail load. Both approaches provide cover against locational price risk using generation in constrained regions (called “local generation” in this paper). Currently there are no specific mechanisms in place to provide spot market participants with cover against locational price risk on power “imported” into their region.

861. This section discusses two transmission risk management initiatives for providing cover on imported power flows, called the hybrid Financial Transmission Rights (the hybrid FTR) initiative and the Locational Rental Allocation (LRA) initiative. Other transmission risk management initiatives that were initially considered by the HMDSG are outlined in Appendix C, and are essentially variants of the above two initiatives.

862. The hybrid FTR initiative is predicated on the view that FTRs provide an effective instrument for parties to manage their locational price risks whilst preserving efficient spot price signals. Under this initiative, the focus is on auctioning FTRs over the main interconnected grid, pre-allocating some FTRs to certain regions, and allocating auction proceeds to transmission customers.

863. The LRA initiative is motivated by the view that rentals should be allocated to electricity purchasers exposed to high locational price risk. The LRA initiative is also motivated by concerns about regional market power and the cost of participating in FTR auctions, and the realisation that pre-allocating some FTRs would require an allocation methodology just as complex as the one for the LRA initiative. Under the LRA initiative the focus is on implementing a rental allocation methodology first and then subsequently considering whether to auction some FTRs.

864. Significant complexities arise with the analysis of transmission risk management because locational price risk reflects the interaction of spot market arrangements, transmission grid issues, and risk management issues. Section 7.1 provides background on underlying spot market and transmission arrangements, and section 7.2 discusses the key problems with current transmission hedging arrangements. The hybrid FTR and LRA initiatives are analysed in sections 7.3 and 7.4 respectively, and a comparative evaluation is provided in section 7.5.

865. The previous section discussed a wide range of generic risk management initiatives, some of which would affect the transmission risk management market. For example, the initiative to publish contract details covers all types of risk management contracts, and therefore affects the transmission risk management market too. Similar comments apply in regard to the development of model master agreements and the publication of fuel and outage information. The initial evaluation of the hybrid FTR and LRA initiatives in sections 7.3 and 7.4 is conducted ignoring these overlapping effects, but they are considered in section 8.

7.1 Background

866. This section discusses the historical development of transmission hedges, the fundamentals regarding locational price risk, loss and constraint rentals, and efficient spot market pricing.

7.1.1 Historical Development of Transmission Hedges

867. The issue of transmission hedges in New Zealand reaches back to 1988 when Grant Read proposed a form of FTR expressed as line shareholding, which was then reproduced by Transpower[19]. The initial work on designing the wholesale electricity market between 1993 and 1996 assumed FTRs would be implemented to allow market participants to hedge against locational price risks and provide incentives for transmission investment.

868. The Grid Services Working Group (GSWG) recommended in May 1996 that rentals should be paid to Transpower as transmission owner, with the intention that Transpower use the rentals to fund transmission hedges. The GSWG also recommended that the proceeds from issuing transmission hedges, and the residual rentals not used to fund transmission hedges, be used to offset common-use transmission charges in proportion to transmission payments. This was thought to be the ‘least distortionary’ methodology by which to allocate the rentals, and was not intended to confer any ownership rights to the rentals.

869. The NZEM commenced in October 1996 with a marginal nodal pricing regime which did not include FTRs or any other means for participants to manage locational price risk. NZEM also commenced without decisions on a permanent methodology for allocating loss and constraint rentals generated by the introduction of marginal nodal pricing.

870. Significant work has been undertaken since the start of NZEM regarding the allocation of loss and constraint rentals and the development of transmission hedges for the New Zealand electricity market.

871. Under NZEM, Transpower was paid rentals, which were then distributed back to participants on the basis of transmission charges paid. HVAC rentals were paid to distribution companies and directly connected consumers. HVDC rentals were paid to South Island Generators that paid the HVDC transmission charges. This methodology was not intended to confer any property rights, but was simply a pragmatic decision made at the start of the market. This methodology has continued to be applied since the EGRs began in March 2004.

872. Transpower developed and implemented a transmission hedge product in 1996, which did not utilise the loss and constraint rentals and was separate from the NZEM. Transpower offered these transmission hedges from 1996 through to 1998, when it withdrew the product and announced its intention to introduce a new transmission hedge product. The new product was based on a design that was initially developed in the United States, and became known in New Zealand as Financial Transmission Rights (FTRs). Unlike the earlier product, the FTR product was to be fully funded by loss and constraint rentals.

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[19] Read, E.G., “Pricing and Operation of Transmission Services: Long Run Aspects” and Read, E.G. & Sell, D.P.M, “A Framework for Transmission Pricing” in Turner, A. (ed), *Principles for Pricing Electricity Transmission*, Transpower New Zealand Ltd., August 1989.

873. Industry consultation undertaken by Transpower on the proposed FTR design revealed that the design did not address the concerns of industry participants. As a result, Mighty River Power and TrustPower proposed a rule change under NZEM to clarify that Transpower did not own the rentals, and could therefore not use them to fund the FTR product.

874. The rule change proposal led to the formation of the Loss and Constraint Allocation Working Group (LCAWG) in 2002, which was tasked with determining an appropriate allocation methodology for transmission rentals. Transpower's FTR proposal included a methodology for allocating auction proceeds and residual rentals, and this was considered as one of the possible allocation methodologies.

875. The Ministry of Economic Development (MED) also commissioned a report from Dr Grant Read on FTRs (the Read Report)[20]. In short, the Read Report recommended implementing Transpower's FTR design, but with the major caveat that some FTRs be pre-allocated to specified parties prior to any auction occurring. The GPS appendix on FTRs essentially follows the recommendations made in the Read Report, stating that the FTR design should be as Transpower's design, but with some pre-allocation of FTRs.

876. The LCAWG determined a set of decision criteria and considered a number of possible allocation methodologies at a conceptual level. It determined that several options were worthy of further attention:

a. Implement FTRs using the rentals, with residual rentals and auction income distributed in accordance with an agreed methodology;

b. Offset rentals against the costs of transmission (i.e. use the rentals to reduce Transpower's revenue requirement);

c. Allocate rentals to purchasers and direct connect customers, either based on peak demands, total energy demand, value of purchases, or rentals paid; or

d. Implement a 'hybrid' FTR model, as proposed in the Read Report. The hybrid could work within the framework set out by Transpower's FTR design, but allowing long-term regional allocation of rentals as well as short term trading to allow changes in position by FTR participants.

877. The LCAWG's final report to the NZEM Rules Committee outlined a number of issues it had with Transpower's FTR design. It also discussed the hybrid approach proposed in the Read Report, and how the hybrid approach addressed some of the issues with the proposed FTR design. Following this report, Mighty River Power and TrustPower withdrew their rule change proposals that had led to the LCAWG being formed, citing changes in the external environment as the reason. No further reports were published on FTRs under NZEM or by Transpower.

878. The Commission is now responsible for the development of transmission hedges, and is required to take the GPS (and its Appendix) into consideration when making decisions.

7.1.2 Locational Price Risk

879. A clear understanding of locational price risk is essential for the evaluation of the hybrid FTR and LRA initiatives outlined in sections 7.3 to 7.5. This section discusses

[20] E. Grant Read, "Financial Transmission Rights for New Zealand: Issues and Alternatives", A report prepared for the Ministry of Economic Development, 8 May 2002.

what locational price risk is, how large it is, why it is so large, and who is affected by it.

What is locational price risk?

880. Locational price risk arises because the spot market is based on different prices at approximately 260 nodes across the national grid. The different prices reflect the cost of transporting energy and the cost of sourcing energy from more expensive sources when the grid is constrained.

881. For example, consider a directly connected consumer located at Kawerau in the Bay of Plenty. Conceptually, fluctuations in the Kawerau nodal price comprise movements in the price of energy at the injection node served by the marginal generator (assume this is Benmore in South Canterbury), plus movements in the difference of nodal prices between Kawerau and Benmore. That is:

Kawerau price = Benmore price + (Kawerau – Benmore) price

or

Kawerau price = energy price + locational price

882. In this example, the Benmore price represents the price of energy the Kawerau consumer could have obtained if it had located close to the marginal generator (i.e. Benmore). The (Kawerau – Benmore) price difference is the locational price for consumers in Kawerau. It represents the additional cost the Kawerau consumer faces for locating away from the marginal source of energy.

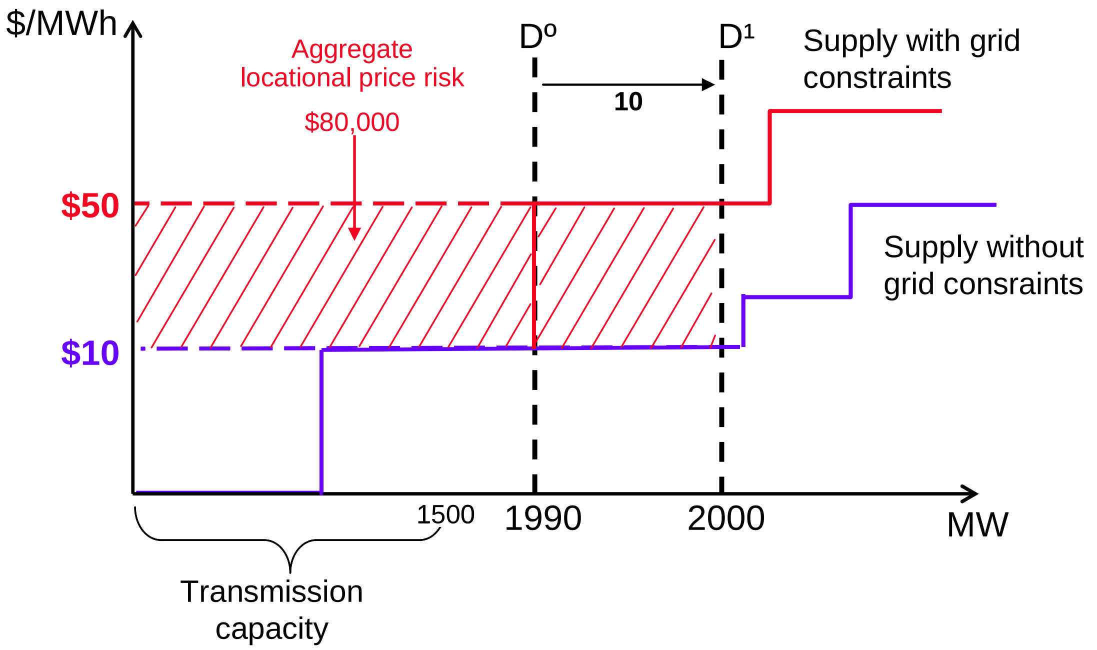
883. In other words, the electricity price risk at Kawerau can be decomposed into energy and locational price risks, as follows:

Kawerau price risk = energy price risk + locational price risk

A numerical example of locational price risk

884. Figure 20 illustrates locational price risk for a situation where demand at a node increases by 10MW (from 1990MW to 2000MW), causing a grid constraint on the 1500MW transmission line to bind and pushing the price up from $10 per MWh to $50 per MWh.

Figure 20: Aggregate locational price risk



885. In this example, purchasers would pay an additional $80,000 per hour as a result of the changes in nodal price. This $80,000 is the difference between the $100,000 per hour paid when aggregate demand is 2000MW and the $20,000 per hour they would have paid for 2000MW if the line hadn't gone into constraint.

The size of locational price risk in New Zealand

886. Figures 20 and 21 show daily and monthly average prices at Benmore since the spot market started in 1996. In looking at this diagram it is important to note that 2001, 2003 and 2006 have all been dry years and exhibit substantial volatility. Figure 20 shows daily average spot prices are highly volatile even during "normal" years, but figure 21 shows that even on a monthly average basis, spot prices are highly volatile.

Figure 20: Energy price volatility: daily average prices at Benmore for the period October 1996 to March 2006

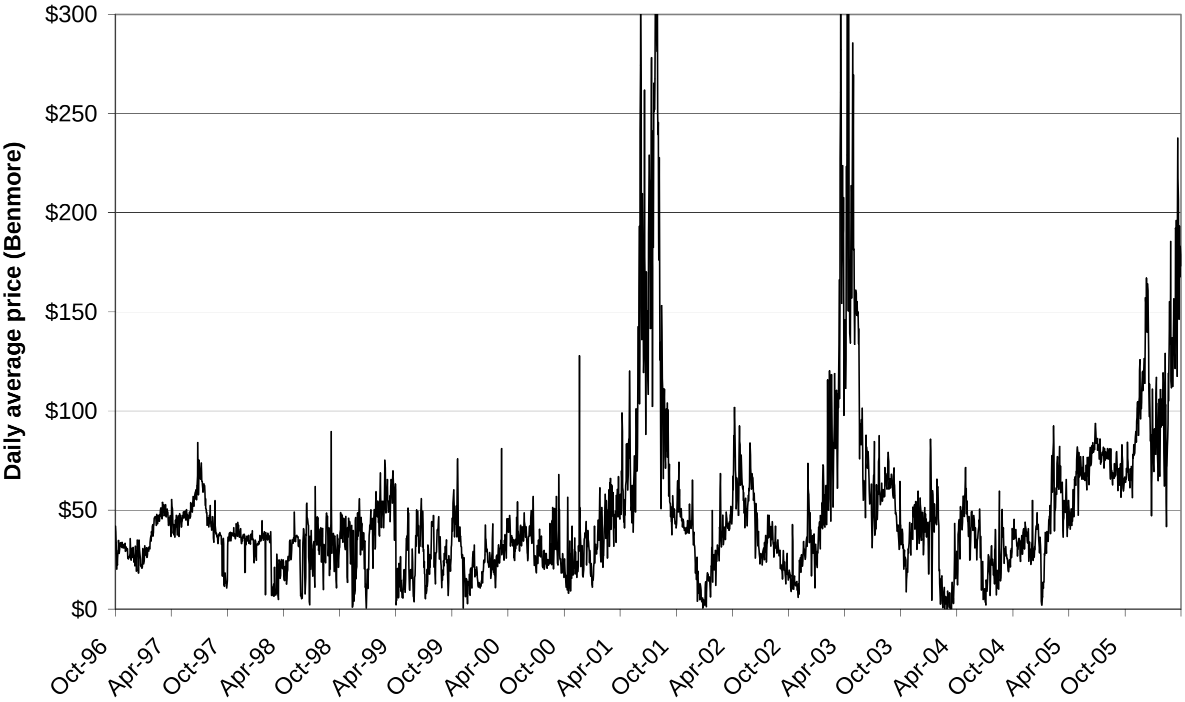
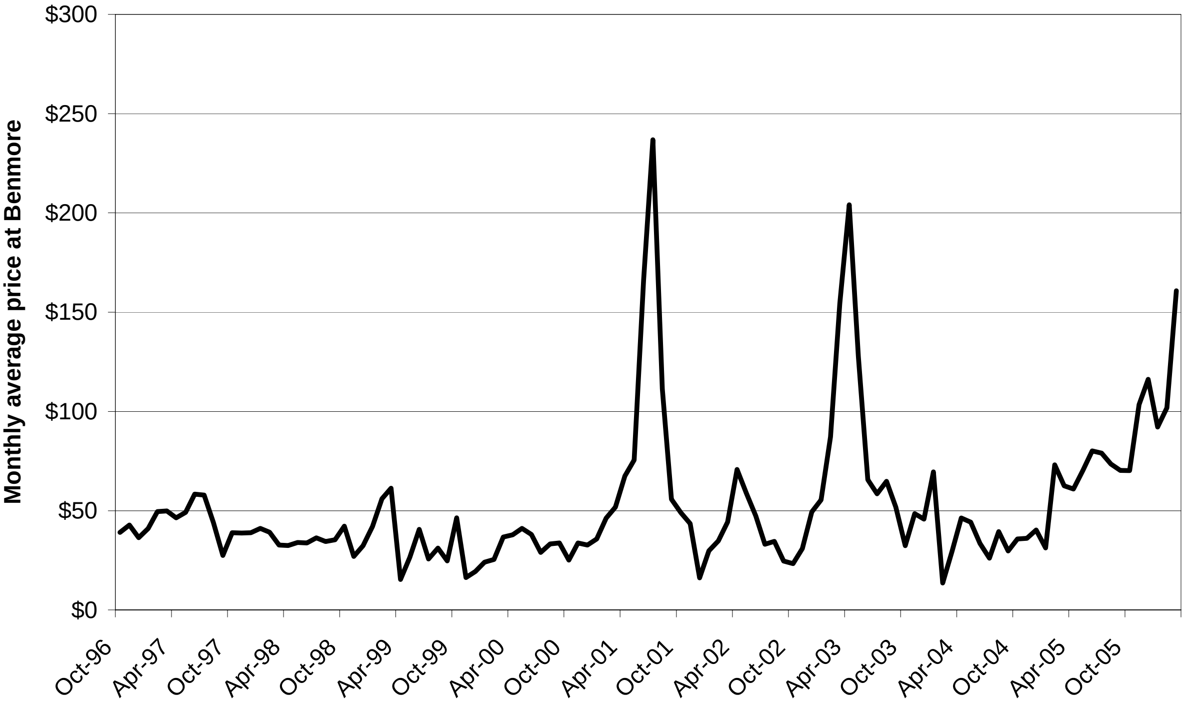
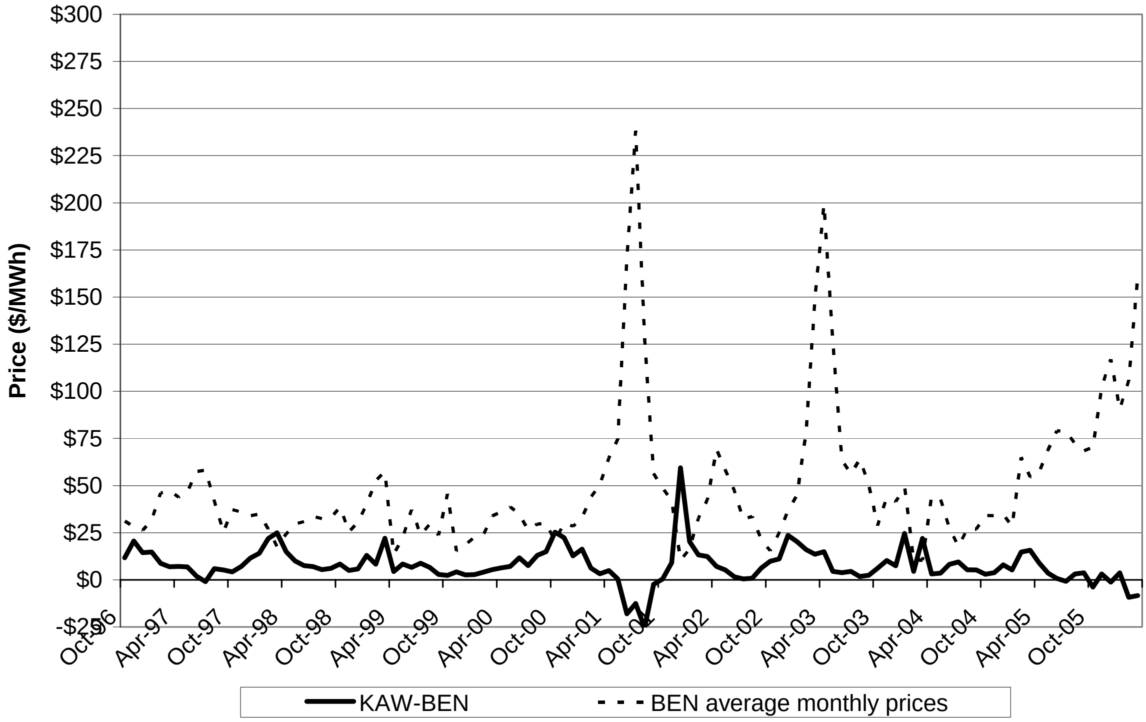


Figure 21: Energy price volatility: monthly average prices at Benmore for the period October 1996 to March 2006



887. Figure 22 plots the monthly average statistics for price differences Kawerau – Benmore against Benmore daily prices. Compared with Figure 21, the graph shows that locational price volatility is also significant. This is also reflected in the standard deviation of $9.35 for Penrose and Kawerau respectively, compared with a standard deviation of $37.32 for Benmore daily average prices.

Figure 22: Locational price volatility: monthly average price deviations from Benmore prices for the period October 1996 to January 2006



The causes of locational price fluctuations

888. There appear to be four main aspects of spot market pricing arrangements that create sharp and sizeable locational price movements:

a. Transmission constraints are “hard-edged”.

b. Short operating periods during grid constraints.

c. Spring washer effects can occur during grid constraints, and

d. Regional market power.

Hard-edged grid constraints

889. Unlike road congestion, where adding a few more vehicles to a slightly congested road slows traffic speed a little, the transmission system is either in constraint or not – there is no half-way house. This is primarily because the system is operated according to a model which has set transmission capacity. By definition, a circuit becomes constrained when the flows on the model indicate that the circuit is fully loaded. In these circumstances, small changes in load or generation patterns on the grid can shift the system in or out of binding constraint, often causing very large price movements over very short time periods.

Short operating periods

890. High prices arise because, in many cases, positioning generation in constrained regions is commercially feasible only if local generators charge high prices during the few trading periods that they operate at high capacity. Similarly, consumers will generally require high prices to commercially justify reducing demand. The occurrence of high electricity prices for short periods of time is therefore not

necessarily an indication of generators extracting monopoly profits, but rather may be what is needed to achieve commercially viable outcomes.

Spring washer effects

891. Spring washer effects occur when a constraint in a loop has to be managed by reducing cheap generation and ramping up more expensive generation[21]. A loop is where power flowing from node A to node C can take multiple paths, such as directly from node A to node C and also from node A to B to C. See Figure 33: Example Grid: AB constrained on page on page 190, section 7.4.3, for an illustration of a loop.

892. The spring washer effect often creates extremely large nodal price differences – for example, provisional prices at Tauranga reached $8,272 per MWh in trading period 36 on 24 April 2004 compared to prices at around $60-80 per MWh normally. The spring washer effect also typically causes high prices at a number of nodes and this will flow into loss and constraint rentals.

893. Additional information regarding spring washer effects can be found under the Constraint Issues Group on the Commission's website.[22]

Regional market power

894. Although high nodal prices may reflect the economic cost of local generation, there can also be situations when local grid constraints leave only one generator available to meet additional demand in the constrained region. In these circumstances, local generators can exercise market power, and the issue becomes whether or not they use their market power to earn monopoly profits.

Other factors

895. There are also other factors contributing to volatility in nodal price differences. For example, the SPD model uses marginal losses rather than average losses in its price calculations. The marginal approach creates greater price deviations than the average approach would. However, compared to the other factors discussed above, the marginal loss approach is a relatively small contributor to nodal price volatility.

Who is affected by locational price risks?

896. Generator/retailers face locational price risks to the extent they buy electricity at nodes exhibiting significant price differences from nodes at which they sell electricity. Although generator/retailers in New Zealand are quite heavily vertically integrated, generation and load are often dispersed across price zones, leaving them exposed to significant locational price risk.

897. Directly connected consumers also face high locational price risks. Consumers close to the main generation centres, such as Benmore, Clyde, New Plymouth, Huntly and Otahuhu, can generally cover these risks by purchasing a single contract to cover

[21] For example, binding grid constraints can create situations when a 1MW increase in load requires cheap generation to be reduced by 10MW and an increase in expensive generation of 11MW. If cheap generation cost $40 per MWh and expensive generation cost $80 per MWh, then the economic cost of supplying the additional 1MW of load equals 11MW x $80 per MWh – 10MW x $40 per MWh, which equals $480 per hour. In contrast, if the cheap generator did not need to be 'backed off' to meet the 1 MW increase in demand, the economic cost would have been only $80 per hour. Note the highest spot price paid to generators in both cases equals $80 per MWh, but consumers in this example pay $480 per MWh. In practice, the locational price differences can be further exacerbated because the upstream prices can also dramatically reduce.

[22] http://www.electricitycommission.govt.nz/advisorygroups/pjtteam/cig/index.html/view?searchterm=CIG

both energy and locational price risk or buy a hedge that is referenced to the consumption node.

898. However, consumers distant from the main hubs, such as in Northland, the Bay of Plenty, or at the top of the South Island, may face a limited supply of contracts because a large proportion of local load is supplied over transmission lines by distant generators. For this reason, generators are generally not so well-placed to accept locational price risks in areas where they do not have significant generation. Also, although some generators may have generation in locations distant from the main hubs, the supply of contracts will often be limited because they need to use their local generation to cover the risks of their local retail load.

899. Similar comments would apply to retailers not owned by generators. If they are located near the main generation centres they would be exposed to locational price risk, but should be able to buy bundled derivatives to cover those risks. Likewise, if they are located away from the main hubs then they would probably face significant difficulty obtaining hedges to cover their locational price risks.

7.1.3 Loss and constraint rentals

900. Loss and constraint rentals are the surplus funds arising from the difference between the receipts from purchasers and the payments from generators that the spot market Clearing Manager collects. Loss rentals arise for completely different reasons than do constraint rentals, but in practice no distinction is made between them when determining the surplus money accrued or distributed by the Clearing Manager.

901. This section discusses the source of loss and constraint rentals, how they are currently allocated to market participants, and their relevance to locational price risk and transmission arrangements.

The source of loss rentals

902. Loss rentals arise because the SPD model (used for the scheduling pricing and dispatch of electricity) prices energy at off-take nodes based on the price offered by the marginal dispatched generator plus the marginal cost of transporting energy from the marginal node. The marginal cost of transport is determined by a formula in SPD designed to approximate the marginal loss of energy – that is, the amount of energy lost if load increased by 1MW. In the absence of market failures, such as externalities and market power, this approach produces the (approximately) correct price for consuming energy as it signals the economic cost of consuming an additional unit of electricity.

903. The 'laws of physics' for electrical circuits mean that marginal losses always exceed average losses, which means the marginal cost of transport always exceeds the average cost of transport. Consequently, the Clearing Manager receives surplus money, because it receives more from spot market purchasers than it pays out to generators.

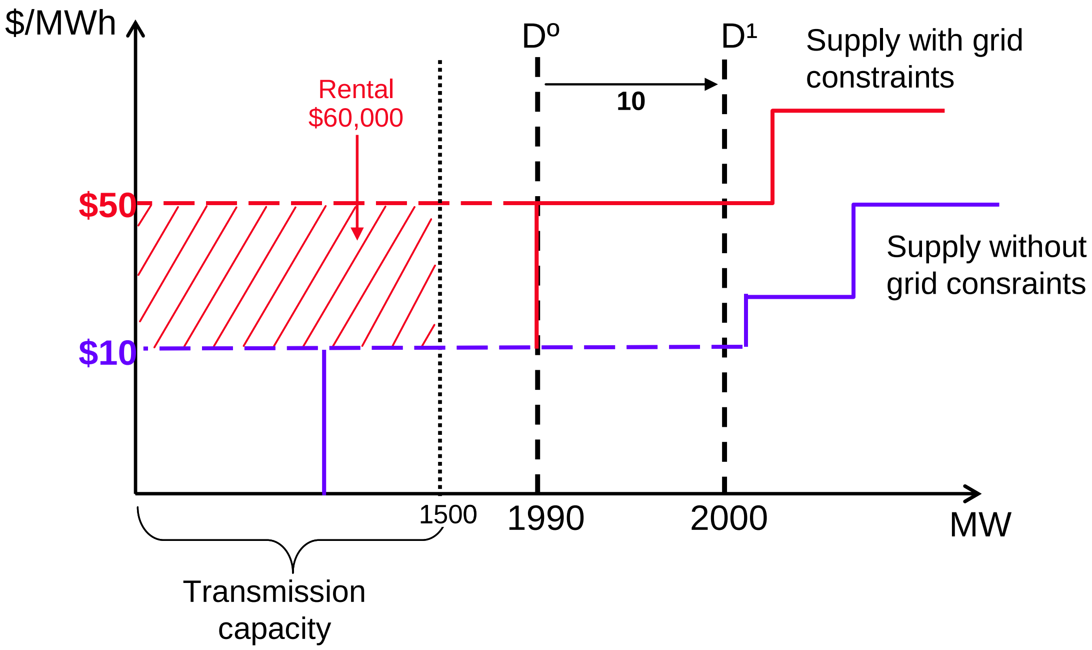
The source of constraint rentals

904. Constraint rentals arise whenever the amount of electricity transmitted on a circuit reaches the circuit's maximum allowed carrying capacity specified in the SPD model – when this occurs, the circuit is said to be a constrained circuit and there are price differences on either side of the constraint. In these situations the SPD model requires that increases in load be obtained from sources of generation that do not increase transmission on the constrained circuit.

905. In simple terms, in the absence of losses, the value of the constraint rental on any constrained circuit equals the price difference between the two nodes on the circuit multiplied by the amount of electricity transmitted from one node to the other. Constraint rentals also arise on circuits that are not themselves “constrained” but are part of loops in which a constraint occurs. The following illustrates the simple case where the circuit itself is constrained.

906. Continuing the numerical example from figure 19, suppose 1,500 MW of energy is transmitted from node A to node B over a 1-hour period, and assume the price at node A is $10/MWh and the price at node B is $50/MWh. The constraint rental in this case is ($50 - $10) per MWh x 1500 MW, or $60,000 per hour. This is illustrated in Figure 23 below.

Figure 23: Constraint rentals



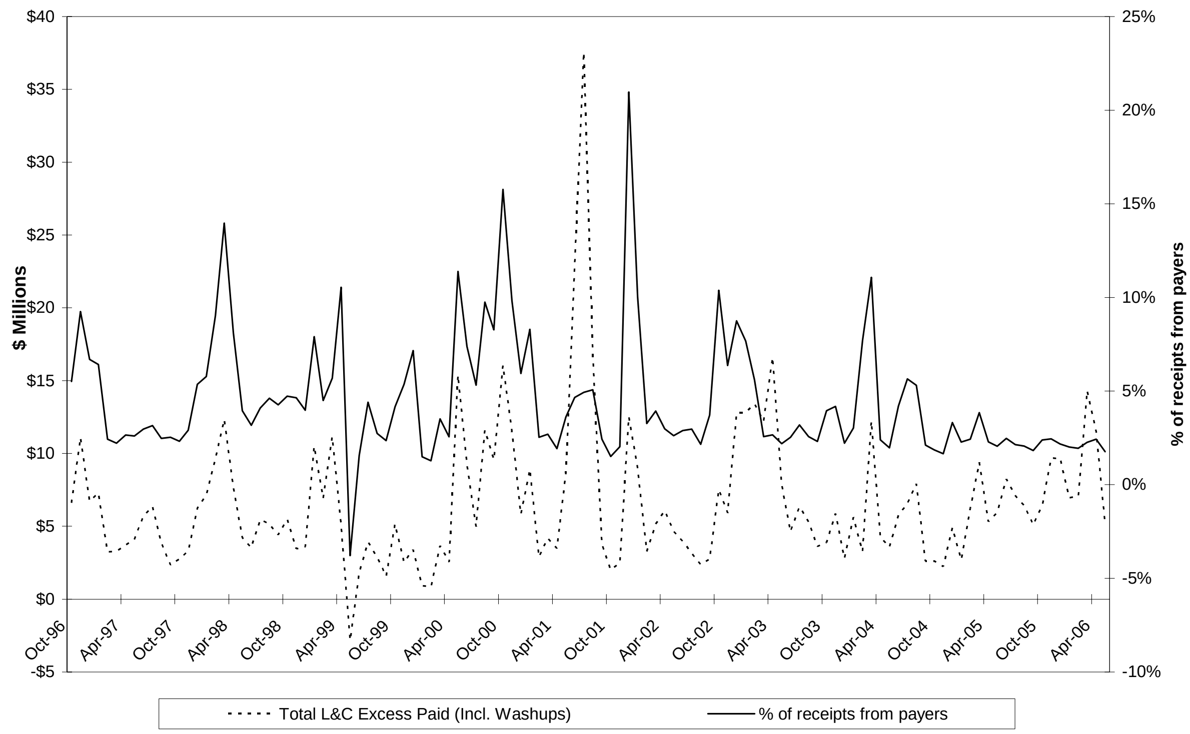
The pool of loss and constraint rentals in New Zealand

907. The total pool of loss and constraint rentals can change significantly in any month, and has a high correlation with the level of constraints occurring in the transmission system. In 2001, for instance, which had a large number of constraints across the grid, the total amount of loss and constraint rentals was $126 million[23]. In 2002, however, the system had very few constraints, and the total amount of loss and constraint rentals was $66.5 million.

908. Figure 24 plots the historical loss and constraint rental payments since October 1996 and displays how these relate receipts from payers. It should be noted that the negative payment in May 1999 was caused by the amount of the washups for previous billing periods that were invoiced in May 1999 exceeding the amount of the L&C excess for the May 1999 billing period.

[23] July 2001 alone was $37.5 million.

Figure 24: Historical Loss and Constraint Rentals



Current allocation of loss and constraint rentals

909. Currently, loss and constraint rentals are collected by the Clearing Manager, who passes the money to Transpower, who in turn allocates them to transmission customers.

910. Rentals accrued in relation to the HVDC circuit are paid to South Island generators who pay HVDC charges to Transpower. Rentals accrued in relation to HVAC connection assets are paid to lines companies and directly connected customers who pay the connection charges associated with those assets. Rentals accrued in relation to HVAC interconnection assets are paid to lines companies and directly connected customers on the basis of interconnection charges paid by those customers. Some lines companies forward their share of the rentals to their customers, including retailers, others rebate these monies to local communities and others pass the expected value of rentals back to consumers via lower tariffs. Retailers are likewise expected to pass this money on to their customers via competitive tariff setting.

911. The ownership of loss and constraint rentals was a very contentious issue among NZEM participants around 2001/2002, as Transpower wished to use them to fund its FTR product. The ownership issue is not particularly important under current regulatory arrangements, as NZEM no longer exists and the Commission has authority via the Rules to determine how the rentals are to be used and allocated.

Rentals and locational price risk for consumers

912. Comparing Figures 19 and 23 shows that loss and constraint rentals cover only a portion of locational price risks. For example, if 25 percent of local load is met from local generation then rentals cover no more than 75 percent of the locational price risk arising from nodal price differences.

913. This means the LRA and FTR initiatives provide only partial hedge cover to spot market purchasers exposed to locational price risk, leaving them to top up their cover

from local generators. Generators also face the same locational price risk for contracts sold at locations distant from their generation.

Rentals and volume risk for local generators

914. In many cases local generators are also local retailers, and will therefore seek to acquire rentals to cover their exposure to locational price risk if they are a net retailer. But even if they were net generators they may still want to acquire rentals, because rentals provide a partial natural hedge against local generation volume risk. The same would apply for independent local generators.

915. The natural hedge arises because local generation volumes are negatively correlated with circuit transfer capacity to a region. For a given level of local demand, grid constraints arising from circuit outages to a region require increased local generation in order to meet demand. Likewise, planned and unplanned generation outages often result in grid constraints, causing high nodal price differences and generating high loss and constraint rentals. By acquiring rentals, generators can stabilise their revenue streams because rentals are high when local generation volumes are low, and vice versa. In effect rentals provide local generators a cross-hedge with imported power flows.

916. It should be noted, that generators who sell export FTRs or sell local energy hedges surrender some of the ability to profit from any local market power. They are limited in their ability to profit (in the short run) by restricting supply in the local market.

Rentals, grid investment, and transmission pricing

917. In the absence of economies of scale in transmission investment, loss and constraint rentals would fully fund grid expansion and explicit transmission charges would not be required to fund transmission[24]. In practice, transmission investment is characterised by large economies of scale, making it efficient to have a single transmission provider and allowing that provider to recover their costs from (regulated) transmission fees.

918. Nevertheless, the theoretical analysis implies that for parties who contracted for a transmission line to get power to a market or to access a generation area would pay a “transmission capacity fee” for the right to get power from A to B. They would get the “right” by being given an FTR (or access to rentals on the line). The right would enable them to effectively face the spot price at B, rather than their local price at A (not counting the cost of actual losses on the line). The capacity fee would pay for the fixed capital and operating cost of the transmission line. If there are economies of scale issues that mean that the rentals did not cover the full cost of the line then there needs to be an additional “common transmission charge” (or “tax”) to cover the shortfall or mechanisms to deal with “free – rider” problems related to parties using the line on a spot basis (facing nodal price differences) without having contributed to the full capital cost of the line.

919. In practice there may be more efficient uses for loss and constraint rentals, such as to directly reduce locational price risks for parties exposed to high spot prices, as in the LRA or hybrid FTR initiatives.

[24] Economies of scale occur when the combined output of two firms can be produced at lower cost by a single firm. For example, suppose two firms are each intending to buy and install a 100 MVA circuit, giving a total capacity of 200 MVA. Economies of scale exist with this investment if it is lower cost for a single firm to buy and install a single 200 MVA circuit.

7.1.4 The efficiency of spot market pricing

920. A key design issue for dealing with locational price risk is how alternative approaches to allocating rentals (and/or the proceeds from FTR auctions) affect the efficiency of spot price signals. This section provides the baseline analysis of the efficiency of spot pricing in a small nodal market.

921. To simplify the analysis most of this section is written on the assumption generators and spot market purchasers are completely unhedged. In practice of course they are hedged, often to quite high levels. The implications of this are discussed after the analysis for unhedged load is presented below.

922. The analysis in this section is also based on the assumption that rentals are rebated to spot market purchasers in ways that are not directly related to their half-hourly consumption levels. It is not clear that this is the case in practice, as lines companies adopt different approaches for passing rentals to their customers, and it appears some companies don't pass any rentals to their customers. This assumption means the allocation is neutral with respect to the efficiency of spot market prices.

The efficiency of spot price signals

923. The starting point for the analysis is whether spot price signals provide efficient incentives or not:

a. If spot prices are efficient then it is generally accepted that spot price signals will be distorted if rentals and/or auction proceeds are allocated on any basis related to the current or future consumption of spot market purchasers;

b. On the other hand, if spot prices are inefficient, then the allocation of rentals and/or auction proceeds can potentially be used to improve the efficiency of spot price signals.

924. In theory there appears to be strong grounds for believing spot prices provide inefficient incentives for large generators and consumers in constrained regions. This is because relatively small changes in generation or load can take the grid in or out of constraint, typically with large nodal price effects.

925. The basic economic model for nodal pricing was developed in 1984[25]. This model shows that nodal pricing produces efficient incentives for electricity generation and consumption on the assumption that grid users are price-takers.

926. The Read Report, however, shows that nodal pricing provides excessive incentives when grid users are not price-takers.[26]

Numerical example of inefficient spot pricing signals

927. Appendix D of the Read Report provides a numerical example of the magnitude of the excessive price incentives. The key driver of the results is the second-order effect grid users receive when they can exert market power over spot prices.

928. Consider a scenario where there is a large load of 100MW and a small load of 10MW, both located at a node served by a transmission line of 110 MW and a marginal generator. Read assumes the market price is $10 per MWh when grid constraints are

[25] Bohn, Robert E., Michael C. Caramanis, and Fred C. Schweppe, "Optimal Pricing in Electrical Networks Over Space and Time," *Rand Journal of Economics*, 15(3), autumn 1984.

[26] See Appendix D of the Read Report.

not binding, and $50 per MWh at the constrained node when grid constraints are binding.

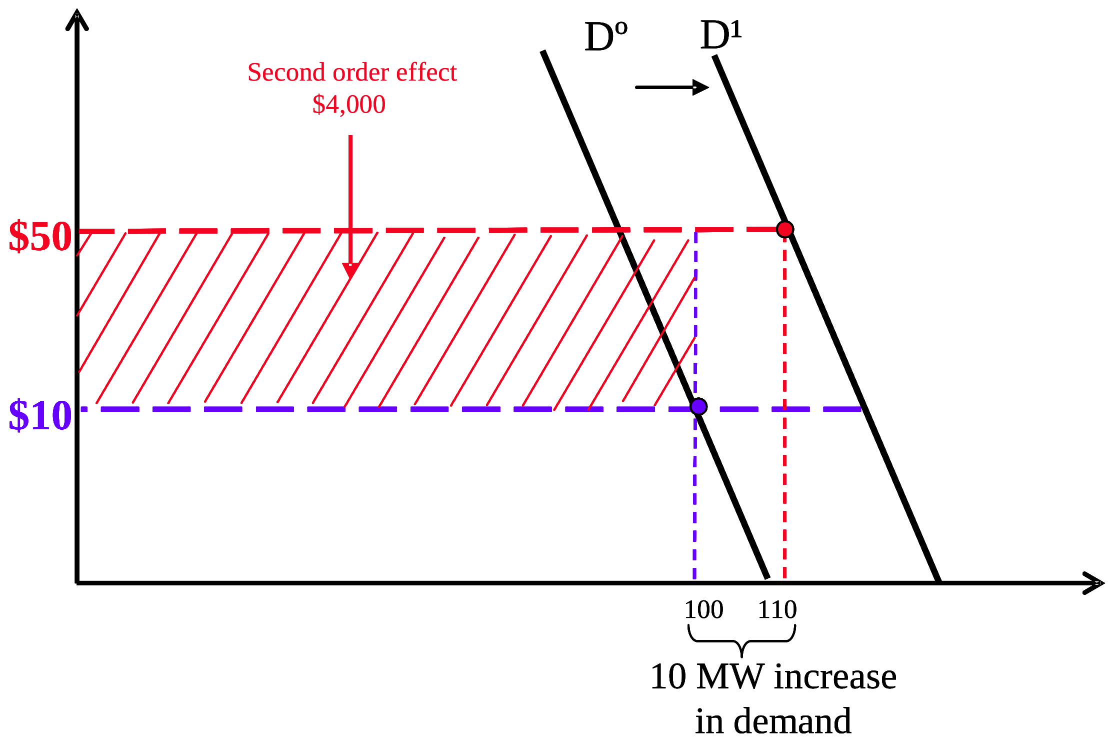
929. Under these assumptions, the nodal price increases by $40 per MWh if either consumer increases load by 10MW causing grid constraints to bind. The marginal price paid by each consumer is the price they paid for their last unit of consumption, which in this example is $50 for both consumers. The nodal pricing system provides the correct marginal price signal, but this signal is only relevant for price-taking consumers.

930. If consumers can alter their load to influence market prices, then the relevant price signal is the *effective incremental price*, which is the additional money paid by the consumer divided by the increment in consumption.

931. For example, if the large consumer increases load by 10MW, it pays an additional $40 per MWh on its existing load of 100MW, with $4,000 additional costs to the large consumer on existing load. This is the second-order effect identified in the Read Report, and illustrated in Figure 25 below.

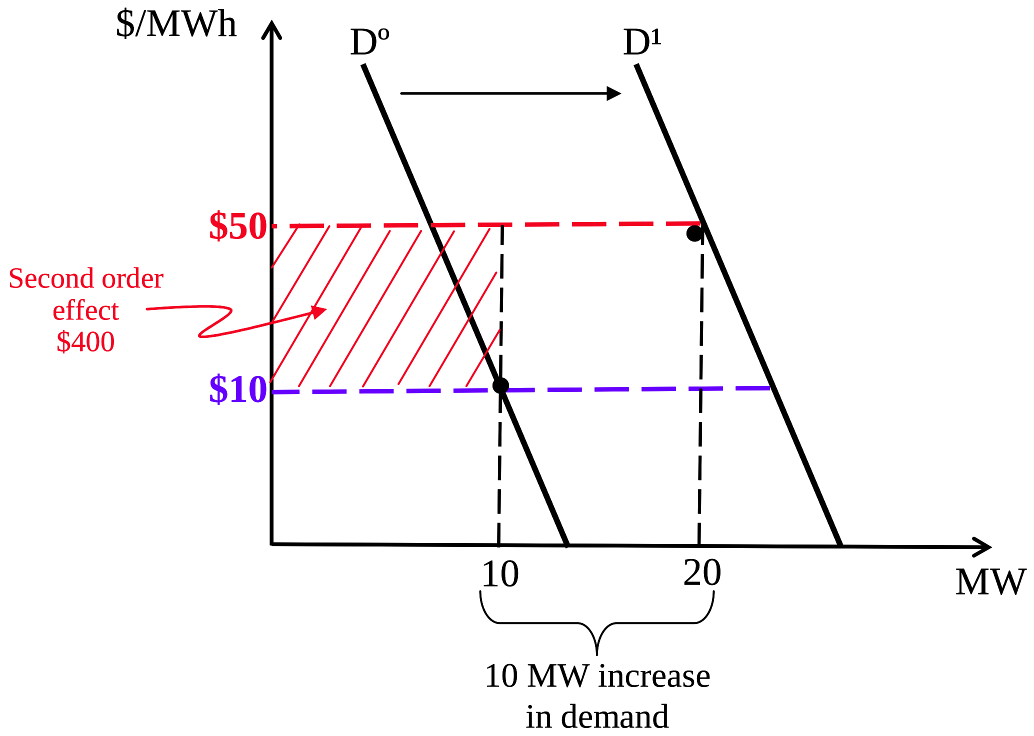
932. The consumer also pays $50 per MWh for the additional 10MW of load, which is an additional $500 paid by the consumer. The effective incremental price is therefore $4,500/10, which is $450 per MWh. This greatly exceeds the efficient price signal of $50 per MWh.

Figure 25: Second-order effects for a large consumer



933. In contrast, the small consumer faces much smaller second-order effects and therefore faces a much lower effective incremental price. If the small consumer increases load by 10MW, it pays an additional $40 per MWh on its existing load of 10MW, giving $400 extra cost to the small consumer on existing load. This second-order effect is illustrated in Figure 26.

Figure 26: Second-order effects for a small consumer



934. The above results are summarised in Figure 27 below.

Figure 27: Effective price signals with no rebates

	Efficient Signal	No Rebates	
	Price-taking Consumers	Small Consumer	Large Consumer
Marginal Price ($/MWh)	50	50	50
Effective Incremental Price ($/MWh)	50	90	450
Gain from 10 MW grid expansion ($)	400	800	4,400

Implications for efficient decision-making by consumers

935. The high effective incremental prices for large consumers provide excessive incentives for them to constrain load to levels required to avoid grid constraints binding. They may do this by reducing their load levels overall, or by locating their load growth to unconstrained sections of the grid, or by shifting their demand to unconstrained trading periods.

936. The large second-order effects also provide excessive incentives for large consumers to lobby for grid expansion, or alternatives to grid expansion. The final row of the table shows the gains from a 10MW increase in grid capacity:

a. Without grid expansion the small consumer pays $50 per MWh x 20 MWh for electricity, or $1000. Grid expansion reduces these costs to $10 per MWh x 20MWh, or $200. Hence the commercial gain to the small consumer is $800;

b. Similarly, the large consumer would pay $5,500 (i.e., $50 per MWh x 110MWh) without grid expansion and $1,100 (i.e., $10 per MWh x 110MWh) with grid expansion. Hence the commercial gain to the large consumer is $4,400.

937. The commercial gains for the large consumer equal $4,400 in this example, but the economic benefits of grid expansion are the avoided costs of using expensive generation rather than cheaper generation, which is only $400 (i.e., $40 per MWh x 10MW). Hence, large consumers face excessive incentives to promote grid expansion, and the same incentives apply in regard to promoting alternatives to grid expansion. Small consumers also face excessive incentives, but not by nearly as much.

What if consumers are hedged?

938. The above analysis critically assumed consumers were completely unhedged at that location, which is very unlikely in practice. The greater the level of hedging, the smaller are the second-order effects discussed above, and the more efficient is the price signal for consumers able to influence spot prices.

939. For example, assume all consumers in the above example are 80 percent hedged at their off-take nodes: the small consumer holds 8MW of hedge cover and the large consumer holds 80MW of cover. As before, assume a 10MW increase in load causes spot prices to increase by $40, from $10 to $50. In this case:

- The second-order effect for the small consumer is only $80 (i.e., 2MW x $40 per MWh), compared to $400 without hedge cover. The effective incremental price is therefore $580/10, which is $58 per MWh. This is relatively close to the efficient price signal of $50 per MWh.
- The second-order effect for the large consumer is only $800 (i.e., 20MW x $40 per MWh), compared to $4,000 without hedge cover. The effective incremental price is therefore $1,300/10, which is $130 per MWh. While this still exceeds by a large margin the efficient price signal of $50 per MWh, it is considerably lower than if the large consumer was unhedged.

940. The first two rows of Figure 28 summarises the above analysis. Clearly, when consumers have the ability to influence price, the level of hedging critically affects the efficiency of spot price signals.

Figure 28: The impact of hedging on effective price signals

Effective Incremental Price	Small Consumer	Large Consumer
Consumer is unhedged (Table 8.1)	90	450
Consumer is 80% hedged	58	130
Consumer is 100% hedged	50	50

941. At the extreme, if consumers are hedged to 100 percent of their initial load levels at their off-take node then there are no second-order effects and spot prices provide efficient price signals, which is $50 per MWh in this case. But 100 percent hedging is

unlikely in practice, so some degree of inefficient pricing is likely to exist under current arrangements.

Efficient decision-making by generators

942. The implications for efficient decision-making by generators are possibly more complicated than that for consumers.

943. The simplest case is where a generator has only a single plant in a constrained region, but the plant is large enough to influence nodal price outcomes. In this case the generator has the opposite incentives to those discussed above for large consumers:

a. They face inefficient incentives to reduce generation, to create grid constraints and high prices;

b. They face inefficient incentives to lobby against grid expansion, or alternatives to grid expansion.

944. If the generator also controls some load in the constrained region, the incentives in (a) and (b) weaken, and disappear altogether if they are perfectly balanced in regard to local generation and load. If they are a net retailer then their incentives are similar to those for consumers.

945. A more complicated case arises when generators own plant in both upstream and downstream locations. This weakens the incentives in (a) and (b) because grid constraints typically increase prices in downstream locations but reduce prices in upstream locations. If they have more upstream generation than downstream generation then normally they have incentives to minimise grid constraints and to lobby for grid expansion.

7.2 Reasons for the lack of transmission risk management contracts

946. Section 3.3.4 identified the lack of transmission risk management contracts as a critical problem inhibiting efficient evolution of the overall risk management market. This section discusses the underlying reasons for the lack of transmission risk management contracts.

947. The discussion in this section is not intended to canvass concerns previously expressed about various FTR proposals. Many of the problems discussed in those debates are in regard to the solution rather than about underlying problems, which is the particular focus below. Problems with particular solutions are discussed in sections 7.3 and 7.4.

948. The key reasons for the lack of transmission risk management contracts are:

a. lack of firm access to rentals, either directly for parties exposed to locational price risk or for other parties wishing to supply FTR products to them;

b. concerns that generators possess regional market power in the spot market;

c. concerns that generators possess informational advantages over consumers; and

d. concerns about the complexity of participating in transmission risk management markets.

7.2.1 Lack of access to rentals

949. The primary problem with current arrangements is the lack of access to loss and constraint rentals, either directly to parties exposed to locational price risk or to parties prepared to supply FTRs to them.

950. If consumers facing high locational price risks received rentals on the imported component of their power, they would only need to purchase transmission risk management contracts from local generators to top up their hedge cover. If their rental allocation exceeded their hedge requirements they would have incentives to sell their surplus rentals to other consumers. Likewise, local generators would have incentives to supply hedges to consumers to the extent their expected local generation exceeded their expected local retail load.

951. If, instead, rentals are not provided directly to parties exposed to locational price risk then they could to be used to fund the provision of FTRs or other similar instruments. Without firm access to rentals, no party would be prepared to bear the risk of supplying FTRs to risk market participants.

952. Transpower is an obvious candidate for supplying FTRs as it “exports” electricity to constrained regions and receives rentals from the Clearing Manager. If Transpower issued transmission risk management contracts without the backing of rentals, it would be left exposed to the offering strategies of generator/retailers and to highly unpredictable spring washer effects. Transpower would require large premiums to compensate for these risks, and since 1998 it has refused to offer transmission risk management contracts without access to rentals.

953. Likewise, in the absence of access to rentals, generators would be reluctant to issue transmission risk management contracts exceeding their expected levels of local generation, as doing so would leave them highly exposed to Transpower's decisions regarding the way it managed the grid. Upstream generators would also be exposed, as they would be exposed to the offering strategies of generators with downstream plants.

954. As the Read Report points out, it is not necessary for Transpower to be the party offering FTRs. For example the Commission could also offer FTRs to the market via the Clearing Manager or some other service provider. Transpower would still need to be involved in determining system feasibility, but this split of technical and market operation roles wouldn't be a problem as it is the current practice in regard to the spot market. But without firm access to rentals, the Commission or service provider would be exposed to the same risks as Transpower.

955. In addition to the above issue of whom to allocate rentals, there are also concerns that, under the current regime, not all lines companies are passing rental rebates through to consumers and retailers. If this is occurring, it deprives affected parties cover against locational price risk.

956. Failure to resolve access to loss and constraint rentals is probably the most critical problem stalling development of the transmission risk management market. Further evolution of the risk management market requires that rentals be allocated either directly to parties exposed to locational price risk or to providers of FTRs – either option would be preferable to the status quo where rentals are not available for risk management purposes.

7.2.2 Concerns about regional market power

957. Consumers have expressed concerns that some generators may possess regional market power in the spot market. These concerns figured prominently in the debate on Transpower's FTR proposals in 2002, with consumers indicating strong reluctance to participate in Transpower's FTR auctions because of their concerns about generator market power.

958. The issue regarding market power and FTRs is whether generators can corner the market in FTRs. Generators may be willing to bid a higher price for FTRs if they can alter prices in the spot market to obtain greater value on the FTRs than a party that doesn't have that market power. Although purchasers may be more willing to buy hedges at a loss in order to prevent larger losses from generators ramping up the spot price, there are only very limited benefits over the long term in taking this approach.

7.2.3 Asymmetric information

959. Concerns about regional market power flow into concerns about generators possessing more accurate and timely information about planned generation outages, and about the likelihood of unplanned plant outages. These information advantages would not matter in competitive regional markets, as nodal prices would be unaffected by plant outages, but in non-competitive situations generators with superior or advanced knowledge of outages are better placed to negotiate derivative prices than consumers.

960. Although generator concerns about their reputation may constrain them from exploiting their information advantages, and information disclosure rules limit those

advantages, consumers nevertheless are likely to be reluctant to participate fully in the transmission risk management market if they believe generators possess regional market power.

7.2.4 Complexity and high transaction costs

961. Concerns about regional market power also flow into concerns about complexity and high transaction costs, which may also limit consumer willingness to purchase transmission risk management contracts.

962. For example, if there are only one or two local generators in a constrained region, then few parties are likely to offer transmission risk management contracts, making it risky for consumers to rely on competing offers for achieving fair value. In this situation consumers would need to value transmission risk management contracts themselves or with the assistance of independent experts, which is costly because of the complexities involved with forecasting nodal prices.

963. An inherent feature of the nodal spot market is that prices reflect a complex interplay of consumer demand, generator offering strategies, plant and fuel availability, System Operator decisions, and Grid Owner decisions. Predicting the locational pattern of nodal prices is considerably more difficult than predicting the overall energy price level, due to the interactions with the grid and the location-specific aspects of the generation issues.

7.2.5 Conclusions

964. The above discussion focused on underlying factors potentially inhibiting efficient evolution of the transmission risk management market. The discussion was framed in terms of interactions between generators and consumers, and the ability or willingness of these parties to participate in the transmission risk management market. Much of the discussion is also relevant to barriers to entry for potential entrants to the retail market, which will be taken into account in the economic evaluation of the initiatives presented in sections 7.3 and 7.4 below, and in the comparative evaluation in section 7.5.

7.3 Hybrid financial transmission rights

Overview

The hybrid FTR initiative involves pre-allocating some FTRs to constrained regions deemed to have inadequate levels of competition in the spot market, and auctioning the rest to the highest bidders.

This initiative would provide purchasers and generators with a flexible means for managing their locational price risks whilst improving the efficiency of spot pricing signals. The main problem with the hybrid FTR initiative is determining which regions or nodes exhibit inadequate competition, defining those regions, and determining how to pre-allocate FTRs to spot market purchasers in those regions. Participation in FTR auctions may also involve significant costs, potentially limiting consumer and small generator participation in the auctions.

The net economic benefit of the hybrid FTR initiative is likely to be moderate and positive, as the baseline case is a situation where parties facing significant locational price risks have limited means for hedging those risks on "imported" power. This situation appears to be critically stalling further evolution of the transmission and energy risk management markets.

Nevertheless, the key issue is whether the initiative is likely to produce greater net economic benefits than the LRA initiative. The comparative evaluation of both initiatives is presented in section 7.5.

7.3.1 Introduction

965. The hybrid FTR initiative provides holders of an FTR with claims to loss and constraint rentals on transmission circuits specified in the FTR.

966. A pure FTR regime involves auctioning FTRs to the highest bidder, and disbursing the auction proceeds to participants who pay transmission charges. This disbursement would be in proportion to their transmission charges. As interconnection charges are currently levied on a postage stamp basis, auction proceeds would be spread nationally.

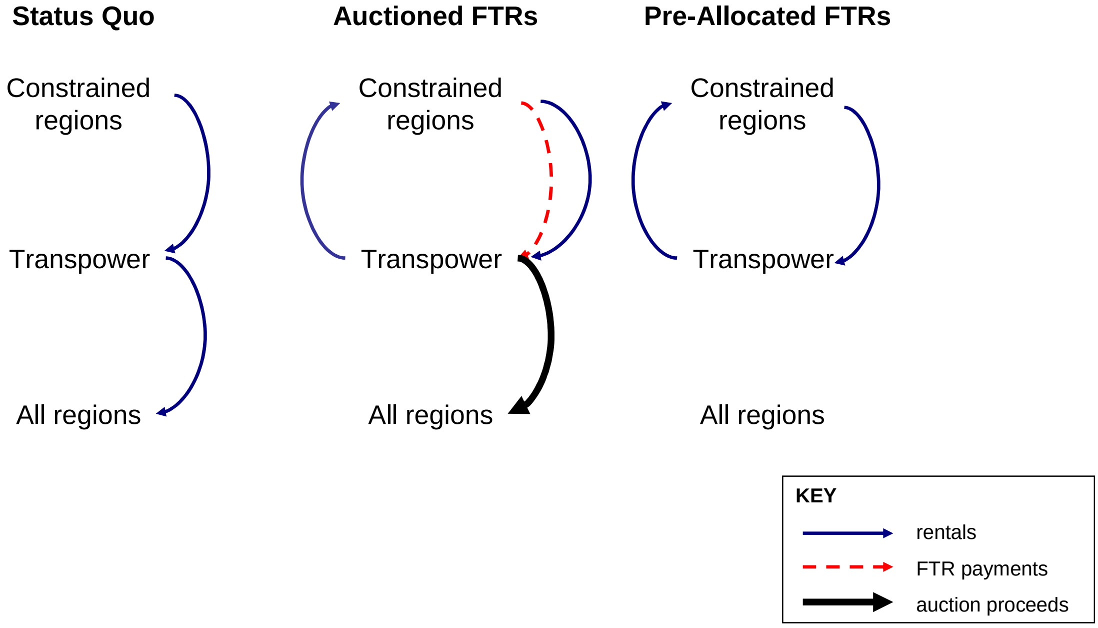
967. Parties buying auctioned FTRs pay the market clearing price per MWh determined in the auction, and in return receive volatile loss and constraint rentals. As the volatile rentals partially offset their payments to the spot market, the overall effect on spot market purchasers would be to stabilise their net profit position.

968. The hybrid FTR initiative also auctions FTRs, but only for nodes for which generator competition is deemed to be adequate. The process for defining regions with inadequate competition is discussed in paragraph 987 and 988. For the remainder of the grid, FTRs would be pre-allocated to spot market purchasers on a gross load share basis. Hence, auction proceeds would be spread nationally and the rentals associated with pre-allocated FTRs would be provided to particular regions deemed to have inadequate competition. This is very similar to the hybrid FTR scheme identified in the Read Report.

969. Figure 29 illustrates the nature of the money flows under the status quo (discussed in section 7.1.3) and the hybrid FTR initiative. Under the status quo, the net money flow is effectively from spot market purchasers paying high spot prices to all spot market

purchasers. For ease of comparison, the fact that some lines companies retain the rentals under the Status Quo has been excluded from the diagram.

Figure 29: Comparison of the money flows for the status quo and pure FTR regimes



970. In general, auctioning FTRs to spot market purchasers doesn't alter net money flows, as payments for FTRs equal rentals received from holding FTRs, assuming that parties can effectively value the FTR.The only effect of auctioning FTRs is to convert volatile half-hourly nodal prices into less volatile monthly prices (assuming a monthly FTR product). In contrast, pre-allocating FTRs shifts the net money flows towards spot market purchasers in regions deemed to have inadequate competition. A more elaborate version of this diagram is provided in section 7.3.4.

971. The hybrid FTR initiative will require the Commission to develop and administer new rules, and to also contract service providers to operate and administer the process for auctioning and allocating FTRs.

7.3.2 Promoter's view

Key problems

972. A key problem identified in section 3.3.4 was the lack of suitable instruments to manage locational price risk. The promoters of the hybrid FTR initiative believe it effectively addresses this problem by auctioning FTRs to the highest bidder, with the expectation that parties exposed to high locational price risk are likely to bid the highest prices and win the auction. Where there are significant concerns about generators exercising regional market power in the FTR and spot market, which would undermine this expectation, the initiative pre-allocates FTRs to spot market purchasers on a load share basis.

Possible economic rationale

973. In theory any party can offer transmission risk management contracts to smooth fluctuations in nodal price differences. In practice, few parties are willing to do so on "imported" power flows as the risks are highly dependent on Transpower's decisions about the way they operate the grid and on the offering strategies of generators operating downstream of the constraint.

974. The economic rationale for the hybrid FTR initiative rests on the view that using loss and constraint rentals to fund FTRs is an efficient use of that income stream, because it allows FTR suppliers to offer spot market purchasers an effective instrument for hedging their locational price risk whilst preserving efficient average and marginal locational price signals. The only situation where efficient locational price signals are not necessarily achieved is where generators are deemed to possess regional market power, but in these cases some distortion to locational price signals is unavoidable under any regime.

7.3.3 Specification of the initiative

975. The key elements of the proposed design are outlined below, and are based on the original Transpower design, with modifications drawn from the Read Report and the GPS.

976. Rather than discuss alternatives regarding the detail of the FTR design, this section presents a single proposal to provide a basis for choosing between the LRA and hybrid FTR initiatives. If the hybrid FTR initiative is chosen as the preferred option, a further round of consultation would occur on the details of the initiative.

FTRs cover both losses and constraints

977. The hybrid FTR initiative would provide FTR holders with claims to loss rentals and constraint rentals. This provides maximum hedge cover for spot market purchasers as they face locational price risk from both losses and constraints.

978. Including losses in the New Zealand FTR design does, however, introduce complexities in finding a balance between overall revenue adequacy and the capacity of FTRs available to participants. This aspect is discussed in a later section.

FTR hubs and nodes

979. FTRs can be defined between any two points on the modelled grid, independent of where generation and load are physically located, and whatever the grid configuration is between those points.

980. Nevertheless, FTR products would be defined in relation to trading hubs, which in this context is a reference node or a collection of nodes that have similar nodal prices. The price at a hub is the weighted-average price of the nodes it covers, and the value of an inter-hub FTR is determined by the inter-hub price difference.

981. Although this approach leaves parties exposed to intra-hub price risks (the risk that the hub price does not reflect a participants nodal price), it is adopted to achieve greater participation at FTR auctions, increase the liquidity of secondary FTR trading, and achieve better alignment with reference points for energy derivatives.

Defining regions with inadequate competition

982. A key component of the hybrid FTR initiative is defining the regions for which competition is deemed to be inadequate to allow auctioning of FTRs. This will be achieved by defining hubs as having two characteristics: (1) all nodes in the hub have near similar prices, after adjusting for marginal losses; and (2) the hub would contain at least two competing generators.

983. Adopting this approach would generate a set of hubs over the interconnected grid where competition is deemed to be adequate. Any nodes not included in a hub

would by default, be deemed to have inadequate competition and would receive pre-allocated FTRs.

Obligation FTRs only

984. The nature of the transmission system means that the value of losses and constraints associated with a circuit are directional. That is, in one direction they have a positive value, and in the other direction they have a negative value.

985. This directional feature has led to the development of two different types of FTR products:

   a. Obligation FTRs, which provide a positive or negative credit equal to the product of the MW value of the FTR and the sink-to-source price difference; and

   b. Option FTRs, which provide only positive credits. FTR options tend to be priced higher than FTR obligations because, unlike FTR obligations, they can never be a financial liability to the holder.

986. For the New Zealand market it is proposed to offer only an Obligation FTR product. The introduction of Option FTRs would be more complex and introduce additional complexity in obtaining revenue adequacy and simultaneous feasibility. These issues are discussed later in this section of the paper.

FTR duration

987. The duration of an FTR is the length of time over which the revenues from the product are calculated and accrue to its holder at the time. The initiative adopts Transpower's proposal for all FTRs to have an initial duration of one calendar month, irrespective of whether they are auctioned or pre-allocated.

988. Monthly FTRs have been proposed as the initial duration to allow participants to gain experience of the auction process. Longer duration FTRs would be introduced over time to ensure that participants receive longer-term benefit from holding an FTR and that a secondary market has opportunity to develop. This staged approach to FTR duration offerings is adopted to reduce implementation risk and build liquidity in the FTR secondary market.

Revenue adequacy

989. Revenue adequacy is an important objective for FTR regimes, and is achieved when rental income is sufficient to meet *target FTR allocations*. The FTR target allocation for each type of FTR equals the megawatt value of the FTR multiplied by the spot price differences between the two nodes (or hubs) specified in the FTR.

990. Revenue adequacy is achieved in two steps, as explained below.

Step 1: The simultaneous feasibility test

991. The first step to achieving revenue adequacy is to limit the quantity of FTRs to a level no greater than the amount of power that can be transmitted over the modelled grid. This is achieved by conducting a simultaneous feasibility test (SFT) during the FTR auction, once bids have been received from market participants.

992. The modelled grid used for the SFT is based on the grid the System Operator expects to be available for dispatching generation over the future period covered by the FTRs. If all goes well the modelled grid matches the actual grid used to dispatch

generation, and the quantity of FTRs issued would be sufficient to cover locational price risks on “imported” power flows.

993. In practice, it is difficult to define an FTR grid that accurately matches the grid assets that will be available in real time. The more conservatively the FTR grid is specified, the greater the chance of achieving FTR target allocations, but the lower the quantity of FTRs available to the market to manage locational price risk.

994. Under the proposed design, the FTR grid used in the final auction for a particular FTR will have any circuits relating to planned outages of more than 96 half hours per month removed from it. The FTR grid proposed for use in earlier auctions of the same FTR will be more conservative than this.

Step 2: Scaling payouts to match total rental income

995. The second step occurs once when actual rental income is known with a high degree of certainty, which is after the FTRs have matured. For example, if FTRs are issued for October 2006, then they mature on 31 October 2006 and the second step is undertaken after that date.

996. The second step involves scaling the payout to each FTR holder so that the total payout, for any defined period, equals the total rental income available over that period. For this initiative, the period over which revenue adequacy is to be achieved is defined as the same as the FTR duration, which is one calendar month.

997. Step 2 is implemented as follows:

a. If there is insufficient rental income available to meet total FTR target allocations in a month, then pay-outs to each FTR holder would be scaled in proportion to their FTR target allocation; and

b. If total rental income exceeds total FTR target allocations in a month, the surplus (called residual rentals) will be allocated to FTR holders by scaling up the FTR payments in proportion to their FTR target allocation.

998. Note the approach in (b) differs from the original Transpower proposal, which proposed allocating residual rentals on the same basis as auction proceeds – that is, to transmission customers in proportion to their transmission charges.

FTR auctions

999. All spot market participants will be eligible to participate in the FTR auctions, as will all transmission customers. There are currently approximately 16 spot market participants. Some larger industrials, however, use current participants to act as there agents in respect of the spot market. These larger industrials, and any other party, may also participate in the auctions provided they meet prudential security requirements discussed below in paragraph 1022.

1000. FTR auctions will be conducted with the objective of maximising auction revenue, with all FTRs for each circuit purchased at the market clearing price for that circuit. Initially, it is proposed that FTR auctions will be conducted on a monthly basis for the month-ahead FTRs. Over time, this will be extended to monthly or quarterly auctions for one-month duration FTR contracts out to 12 months ahead.

1001. The monthly auction would be accompanied by a ‘reconfiguration auction’ to allow new FTRs to be created from existing ones (‘reconfiguration’), trading of existing ones, and selling any FTR capacity previously unsold. A 'reconfiguration auction' will only be possible once FTRs of more than a month's duration have been issued.

Obtaining pre-allocated FTRs

1002. Pre-allocated FTRs will be provided to parties exposed to locational price risks, using an allocation methodology based on gross load shares. Pre-allocation of FTRs will occur when:

a. the FTR is identified as susceptible to influence from participant market power, as described above; or

b. the FTR relates to underlying assets that are subject to a specific investment agreement that includes firm transport rights or that is physically owned by the party.

1003. In general, FTRs related to competitive interconnection assets[27] will be obtained through auction. FTRs that are subject to pre-allocation will generally be related to connection assets. However, not all FTRs related to both connection assets and interconnection assets will necessarily be subject to pre-allocation.

1004. Pre-allocated FTRs will be included in FTR auctions so that their quantity is taken into account in the SFT, and so that payouts can be scaled to their target allocation value. Pre-allocated FTRs will be reserved out of the auction by setting very high reserve prices. The Commission will establish the process for setting this reserve price during rule development. Parties with pre-allocated FTRs will receive either the consideration paid at auction if the reserve price is met or the FTR payment stream that subsequently flows if bids do not meet the auction reserve price. Parties will not have to pay for pre-allocated FTRs.

Allocation of auction revenues

1005. FTR auction revenues will be allocated to transmission customers in the same manner that loss and constraint rentals are currently allocated. In particular, auction revenues will be paid to the parties that pay the transmission charges in accordance with the methodology determined under section IV of part F of the Rules.

1006. Currently, this is likely to involve auction income related to connection assets being allocated according to transmission customers' share of connection charges for those specific assets, and auction income related to interconnection assets being allocated according to transmission customers share of interconnection charges. Revenues relating to HVDC assets will be paid to those parties who pay the HVDC charge. Should the transmission charging methodology be changed, the auction revenue allocation would also need to be adjusted.

1007. This is similar to the Transpower FAIRR methodology.[28] The main difference is that, under this proposal, certain FTRs will be effectively reserved out of the auctions and

[27] The Read report used the term "core transmission system" rather than "interconnection assets". However, the term "core grid" is defined under the Rules. The term "interconnection assets" refers to non-connection assets apart from the HVDC, with the term "connection assets" defined in the Transmission Pricing Methodology. In this case, the more appropriate term to use is that of "interconnection assets", and to avoid confusion, this is the term used.

[28] FAIRR stands for FTR Auction Income and Residual Rentals. It was proposed as a simplified version of the then-current rentals allocation methodology, not separating out HVDC, connection and interconnection amounts, and paying on a national spread based on the proportion of sunk costs paid. As stated earlier, the proposal in this paper treats residual rentals differently than under the FAIRR approach.

so will not provide auction revenue to be allocated through this mechanism. The proposed revenue allocation also differs from the approach suggested in the Read Report, which argued a case for regional allocation of auction revenues

1008. So as to not increase any locational price distortion, distribution company transmission customers will be required to pass through these revenues to their customers in the same manner that they charge customers for transmission charges.

Allocation of FTR payments

1009. FTR holders receive settlements irrespective of whether the FTR was purchased at auction or pre-allocated. The payments for auctioned FTRs are based on the MW quantity ‘dispatched’ in the FTR auction, but some other basis for making payments is required for pre-allocated FTRs.

1010. It is proposed that payments for pre-allocated FTRs be provided to spot market purchasers, with spot market purchasers receiving shares of the FTR payments according to their loads at the nodes concerned. That is, a monthly allocation to purchasers by GXP/node, pro-rated in proportion to the gross load of the purchaser at the node.

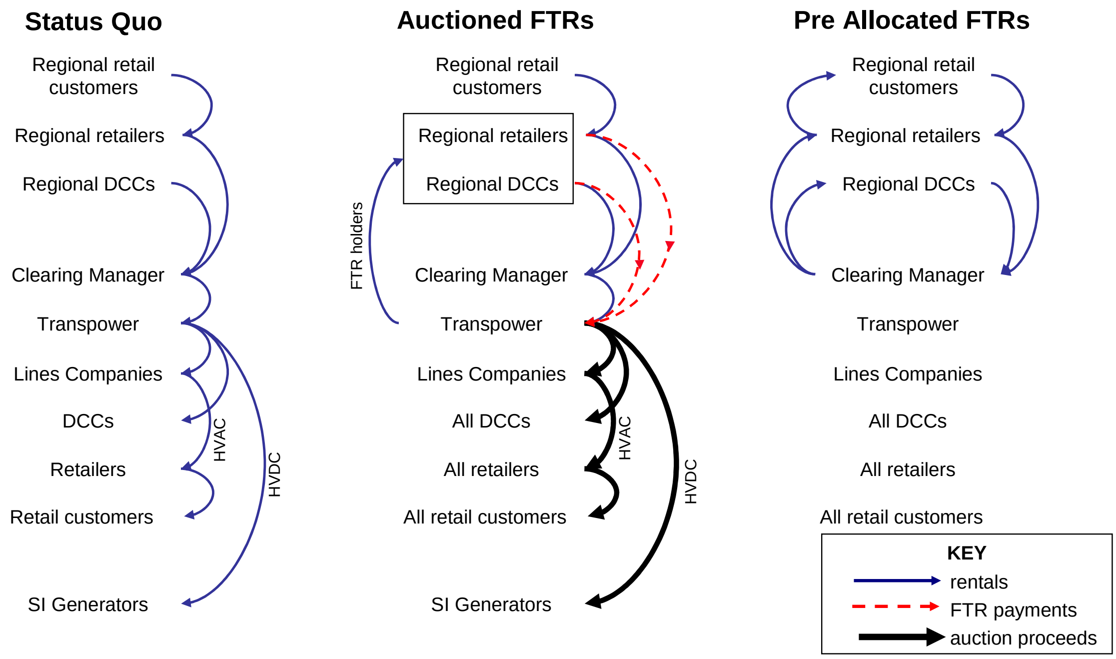
1011. This approach provides the holders of pre-allocated FTRs with maximum cover against locational price risks, and improves the efficiency of price signals for large consumers. The proposed allocation of FTR payment is different from the allocation of auction revenues, which is intended to minimise the impact of the allocation on spot pricing signals because auctioned FTRs have already addressed the locational price risk issue.

1012. To avoid the potential for confusion between payments of auction revenues and pre-allocated FTR payments, it is proposed that the FTR payments be managed by the Clearing Manager making the payments directly to spot market purchasers.

Illustration of money flows

1013. Figure 30 provides a detailed illustration of the money flows under the status quo and the hybrid FTR initiative. For ease of reference, consumers located at nodes experiencing locational price risk are called “regional retail customers” and “regional directly connected consumers”, to contrast them with all consumers. The term “regional consumers” is used in the text where the reference is to retail and directly connected consumers.

Figure 30: Hybrid FTR is a mix of auctioned and preallocated



1014. Under the status quo the Clearing Manager receives loss and constraint rentals that are in effect paid by regional consumers. As discussed in section 7.1, the rentals earned on the HVAC nodes are expected to be eventually paid to all consumers via Transpower, lines companies, and retailers. The rentals earned on the HVDC are paid to South Island generators, as they pay for the HVDC link.

1015. Figure 30 shows that the status quo results in net money transfers from “regional consumers” to all consumers and to South Island generators. Provided a key assumption holds, auctioning FTRs has no effect on the net money flow relative to the status quo. The key assumption is that the parties that win the FTR auction bid values equal to the net present value of the rentals associated with the FTRs. Under this assumption, regional consumers purchase FTRs from Transpower (the dashed line) and Transpower pays them the same amount of money in rentals. Transpower then distributes the FTR auction revenue in the same manner as the status quo. Given these assumptions, auctioning FTRs simply converts volatile half-hourly nodal price differences into less volatile monthly nodal price differences.

1016. The right-hand-side of Figure 30 shows that pre-allocating FTRs tends to neutralise the money flows from regional consumers to the Clearing Manager. Relative to the status quo, there is a net money transfer to regions deemed to have inadequate competition. In other words, auctioned FTRs preserve locational price signals, whereas pre-allocated FTRs do not. Note also that it might be possible to charge customers for the pre-allocated FTRs if there was a problem in this regard. This would however require the Commission or someone making a central assessment of the long run expected value.

1017. Note the initiative achieves full rebating of rentals to consumers facing high electricity prices if lines companies fully rebate the rentals to retailers, and retailers fully rebate rentals to their customers. Even if full rebating does not occur, the geographic distribution of net money flows is the same as discussed above.

Secondary trading of FTRs

1018. There are two ways of buying or selling the tradable FTRs that have been allocated or purchased in a previous auction:

- By bilateral trade. This is effectively an "assignment", whereby the rights and obligations of an FTR previously allocated through an auction are assigned to another participant. Only existing FTRs can be traded and new ones cannot be created in this process; and
- Through the monthly reconfiguration auction described earlier.

1019. As the specification is for an obligation FTR, holders of FTRs may sometimes owe money to the Clearing Manager. Hence, all parties trading on the secondary market will be required to meet prudential security requirements discussed below, paragraph 1021. However, it is unlikely that there will be much trading on the secondary market, although the proposal should not inhibit parties trading on a secondary market if they wish to.

Settlements and prudential arrangements

1020. FTR settlements are against final nodal prices generated in the spot market, subject to the revenue adequacy requirement for each settlement period (i.e. for each month). Washups in the spot market (that affect rentals or final prices) will flow through into FTR settlement.

1021. In order to minimise default risks, all FTR participants would be required to meet defined prudential security requirements. The means of quantifying the security requirements is not defined but would be a net settlement approach (netting off price paid for the FTR in the auction against forecast FTR income). For spot-market participants, this would be linked with spot-market prudential security arrangements.

FTR market operator

1022. As the Read Report pointed out, parties other than Transpower can provide auctioned FTRs provided they have firm access to loss and constraint rentals to fund FTRs and appropriate technical arrangements with Transpower. As the auction business is essentially a monopoly, the right to conduct FTR auctions will be tendered to obtain the best outcome for market participants.

Participation and disclosure rules

1023. The above description covers the "mechanics" of the hybrid FTR initiative. As with other markets regulated by the Commission, a suite of rules would be needed to govern participation in FTR auctions. Information disclosure rules may also be required to monitor market power concerns.

7.3.4 Impact on locational price risk and pricing signals

1024. Before discussing the potential costs and benefits of the initiative, it is useful to first understand the impact the initiative has on locational price risk and pricing signals arising from the spot market.

Impact on locational price risk

1025. In general, FTRs provide spot market purchasers with potential hedge cover against locational price risk on "imported" power to a constrained region. At the individual circuit level, an attractive feature of FTRs is that they provide hedge cover for locational price risks relating to individual circuits and nodes, and hence should be well-tailored to the needs of individual spot market purchasers.

1026. However, with FTR auctions there is no guarantee that the volume of FTRs available for any specific circuit or node will match the volume of "imported" power on the circuit, as the combination of FTRs issued by the auction process depends on bids received in the auction. Moreover, there is no guarantee that spot market purchasers will obtain the FTRs ahead of other parties bidding in the auction.

1027. In practice, the intention is to specify FTRs in regard to hubs rather than just nodes. This approach may further reduce the hedge cover available to individual spot market purchasers, because they will receive FTR payments related to inter-hub price differences rather than inter-node price differences. For this reason, the hub locations should be selected with a view to minimising this effect.

Impact on spot price signals

1028. The efficiency of spot market price signals was outlined in section 7.1.4, where it was shown that second-order effects mean that spot prices provide excessive incentives for large consumers to reduce load when grid constraints are binding.

1029. The hybrid FTR initiative corrects these excessive incentives, but only to the extent to which the FTR matches the net load (i.e. load less generation and hedges at the location) of spot market purchasers:

a. If a spot market purchaser holds FTR volume slightly less than its net load, then the second-order effects associated with changes in spot prices will largely be offset by the FTR payments to it, and the effective incremental price will be close to the efficient level; and

b. If, however, FTR volumes are significantly less than the net load, the FTR payments will be significantly less than the second order pricing effects and the effective incremental prices will remain high. The converse applies when FTR volumes exceed net load levels.

1030. In aggregate, the FTR auction should achieve the desired outcome as stated in paragraph 984(a), as the aggregate volume of FTRs should be closely related to aggregate "imported" power flows. Figure 31 summarises the above discussion, and compares the outcome under the three scenarios considered so far in section 7.

Figure 31: Effective price signals with auctioned FTRs ($/MWh)

Effective Incremental Price	Price-taking Consumers	Small Consumer	Large Consumer
No rental rebates – Figure 27	50	90	450
Auctioned FTRs equal to 90% of total hedge requirements	50	50	54

1031. Importantly, auctioned FTRs do not distort spot price signals for price-taking consumers. This is because FTR payments are fixed by the volume of FTRs held by the consumer, which means they receive the same FTR payments regardless of their level of consumption.

1032. One issue to consider is the effect of pre-allocating FTRs. Provided the volume of pre-allocated FTRs is small, their effects on price signals is small.

7.3.5 Potential benefits

1033. At a high-level the potential economic benefits of the initiative are similar to those for the LRA initiative, as defined in section 7.4. The benefits depend on:

a. whether the initiative facilitates more efficient management of locational price risk;

b. whether the developments in (a) flow through to more efficient levels of liquidity in the energy contracts market;

c. whether the initiative affects barriers to entry in the retail electricity market;

d. how the initiative affects consumption and investment decisions;

e. whether generators have the ability to game the spot market and, if so, how the initiative affects generator incentives; and

f. Whether the initiative improves information for making transmission investment decisions, and whether it reduces incentives for unproductive lobbying for, or against, transmission investment proposals.

More efficient management of locational price risk

1034. The hybrid FTR initiative has the potential to provide parties exposed to locational price risks with new options to manage their locational price risk:

a. For load parties distant from the main generation hubs, the initiative provides a mechanism for managing their locational price risks. These parties currently have very limited options for managing those risks and this initiative should achieve significantly more efficient management of those risks; and

b. For load parties located near the main generation hubs, the initiative provides an additional option to bundled contracts to manage their locational price risks. This should be efficiency enhancing as generators and consumers can continue to use bundled contracts if such contracts are a more commercially advantageous option for managing those risks.

1035. Another area of potential efficiency gain is in regard to horizontal and vertical integration. FTRs may provide retailing businesses, distant from the main generation hubs, with a more efficient option for managing their locational price risks than owning local generation. If that occurs, generator/retailers may face commercial incentives to change the structure of their businesses, divesting their local generation for example.

1036. The efficiency benefits discussed in both paragraphs above may be tempered by the complexity and costs for parties to participate in FTR auctions, which may limit participation in FTR auctions. These concerns arise particularly for smaller generators, and also for consumers who are exposed to spot market risk but want to focus on their core business rather than on the details of how the power system works and likely future spot prices.

1037. The hybrid FTR initiative may also bring greater efficiency gains by shifting the volatile rental flows from lines companies to FTR holders. As lines company costs and revenues are not related to nodal price differences, the current approach of allocating the loss and constraint rentals to them increases the volatility of their annual net income position relative to a situation where they didn't receive rental rebates. Under the Hybrid FTR initiative lines companies will instead receive a more stable annual revenue stream, reducing their net income volatility (and reducing the net income volatility of FTR holders).

More efficient depth and liquidity in the energy contracts market

1038. If spot market purchasers more readily rely on FTRs to manage their locational price risks, then energy contracts may consolidate around one or two reference nodes, creating greater liquidity in the energy contracts market and greater standardisation of energy contracts. As any increases in market depth and liquidity occur voluntarily, they are likely to be efficiency enhancing.

Reduced barriers to entry in the retail market

1039. In principle, the hybrid FTR initiative could significantly reduce barriers to entry for parties seeking to enter retail markets in constrained regions of the grid, distant from the main generation nodes. Auctioned FTRs should address the lack of instruments in these cases where regional market power is not an issue, and pre-allocated FTRs should provide cover for the situations where there are concerns about regional market power.

1040. In practice, the one month duration of FTRs, and the need to compete for them in monthly auctions, is likely to provide only limited ability for new entrant retailers to manage locational price risks on their investment. Hence, auctioned FTRs may not carry significant implications for retail entry until longer duration FTRs are introduced. Although pre-allocated FTRs may also have one-month durations, recipients are likely to treat their allocations as relatively long term provided they are confident the allocation methodology will not be materially altered.

1041. Dealing with the regional market power issue is also not as straight forward as suggested above. For example, there may be situations where officials have deemed a region or node to be competitive when in fact it is not, and vice versa. Moreover, FTRs cover locational price risk only on “imported” power flows, leaving new entrant retailers exposed to market power on contracts with local generation.

1042. The above discussion was in regard to retailing in constrained areas distant from the main generation hubs. The hybrid FTR initiative is unlikely to significantly affect retail entry serving load close to the main generation hubs as bundled OTC contracts are generally available in those areas anyway.

1043. The overall effect on any retail barriers to entry appears to be limited to constrained areas distant from the main generation hubs, and likely to be significantly curtailed by the short duration of auctioned FTRs.

More efficient consumption and investment decisions by large consumers

1044. The more efficient pricing signals for small and large consumers, shown in Figure 31, means they will make more efficient consumption and location decisions. The efficiency gains on longer-term decisions may be large over the long term. Likewise, the hybrid FTR initiative would also improve the efficiency of consumer decisions to participate in the reserves market.

1045. In practice some of these efficiency gains will be tempered by inaccuracies in the methodology for assigning pre-allocated FTRs, but these effects are likely to be minor under this initiative because most FTRs will be auctioned.

1046. The above results assume the volume of FTRs held by consumers will be less than their net load levels. While this is likely to be the case in aggregate, there may be instances when a consumer holds more FTRs than its net load level. When grid constraints occur, these consumers have incentives to increase their net load levels up to their volume of FTRs, in an attempt to increase spot prices, because the money they make on their transmission risk management contracts will exceed the net cost of the additional load. This situation is not expected to occur often, and is assumed to have an essentially zero impact on the cost-benefit analysis.

Reduced generator gaming incentives

1047. Generator incentives are the converse of the spot pricing incentives for consumers, but are more complicated. Consider a generator/retailer with a net generation position in a constrained region and a smaller net generation position (or a net retail position) upstream of the constraint. Under the baseline scenario, these parties sometimes have incentives to game the spot market by adopting offering strategies that cause grid constraints to bind to raise prices in the constrained region and lower prices in the upstream regions.

1048. The hybrid FTR initiative reduces these gaming incentives as the FTR payments received by generator/retailers partially offset the second-order effects discussed earlier in this section. To the extent gaming occurs under the baseline case, the hybrid FTR initiative would likely lead to more efficient spot pricing signals.

1049. Just as the incentives are perverse for consumers holding excess FTRs, the same applies for generator-retailers. If this is considered to be a serious risk, the FTR auction could be modified to bar certain parties from buying certain rights, which is a moderate form of “pre-allocation”.

Reduced lobbying and litigation activity

1050. FTRs were originally developed in the United States to facilitate voluntary grid investment. In New Zealand, however, grid investment is determined under part F of the Rules, with the Commission, in conjunction with Transpower, responsible for determining grid investment. As a result, FTRs will not affect grid user willingness to build or fund grid expansion, except where pre-allocation is based on a transmission investment agreement.

1051. Relative to the baseline case, the hybrid FTR initiative greatly reduces the disparity between the commercial and economic benefits of transmission investment. The pre-allocation aspect of the Hybrid FTR initiative will reduce wealth transfers and therefore reduce consumer and generator/retailer incentives to lobby for (or against) transmission investments. It should also greatly reduce incentives for parties to litigate such decisions.

1052. As excessive lobbying and litigation activity is unproductive activity, the hybrid FTR initiative frees up resources for more productive activities.

More efficient transmission investment

1053. The auction of monthly FTRs out to 1 year may enhance transmission investment decision-making as the value of the FTRs obtained through the auction process, and as shown through secondary market trades, should give an indication of participants’ views on future nodal price separation. This information could potentially be useful to the Commission and Transpower for identifying areas where new transmission investment is required.

1054. In addition, if the Rules were amended for some reason in the future to allow parties other than Transpower to build new transmission, having FTRs in place would help facilitate revenue streams for parties making such investments.

7.3.6 Costs and risks

1055. The potential costs and risks of the initiative relate mainly to:

a. lack of flexibility for innovation;

b. rule development costs;

c. costs of implementing and administering FTR auctions;

d. costs to participants to participate in FTR auctions;

e. risks of low participation and gaming in FTR auctions;

f. complications with defining regions and hubs with inadequate competition;

g. complications with defining pre-allocated FTRs, and the costs of implementing systems to allocate rentals for pre-allocated FTRs; and

h. revenue adequacy

Lack of flexibility for innovation

1056. FTR regimes provide a centralised set of auctions, with contract specifications and settlement arrangements determined on a centralised basis. While this approach achieves a standardised product, it nevertheless provides a ‘one size fits all’ solution to managing locational price risk. Little flexibility is left for new independent providers to offer innovative products and solutions.

Rule development costs

1057. Implementing this initiative would require the Commission to develop a suite of rules regarding the provision of FTRs, participation in FTR auctions, and the payment of FTR claims and auction proceeds. One-off costs would be incurred to develop, consult, and finalise the rules, and a further one-off cost would arise to refine them at a later date.

Costs of implementing and administering FTR auctions

1058. The hybrid FTR option will involve a significant change to the current methodology and process. Despite substantial investment already spent on systems development by Transpower, there will still be significant cost in establishing the infrastructure and the FTR market rules and mechanisms to implement the initiative.

1059. Additional implementation costs would be incurred if the Commission chose to tender the FTR market operator role, although the expectation would be that these costs would be more than offset by the cost savings gained from a competitive tender as otherwise the tender should not be held.

1060. There will be ongoing costs associated with management and operation of the monthly auction process, but the scale of these will depend on the chosen infrastructure and the range of FTR products offered to the market.

1061. There will be a continual requirement on the FTR provider to manage the FTR grid and inform participants of those changes. This will become more onerous when a range of FTR duration products is offered and FTR auction tranches are introduced.

Participation costs

1062. The underlying value of auctioned FTRs derives from the value of loss and constraint rentals, which in turn depend on real time load and generation patterns and the state of the grid. Bidding in FTR auctions will, therefore, require participants to have a detailed understanding of the spot market and sophisticated modelling expertise.

1063. Parties wishing to participate in FTR auctions will need to invest significantly in these resources, and incur ongoing monitoring and evaluation of the factors driving the spot market. Considerable senior management time and Board approval will likely be required for participants to approve participation in FTR auctions, especially the concept of two-way settlement.

Low participation risks

1064. Successful implementation of the hybrid FTR initiative depends on having a high level of participation by the various classes of participants, across the full range of auctioned FTR products. This is likely to be difficult to achieve with the small number of participants in the New Zealand market.

1065. The high cost of participating in FTR auctions has the potential to undermine widespread participation in the auctions. As a result there is a significant risk the initiative will fail to deliver competitive FTR bids over the majority of the grid.

1066. There is also a risk that a FTR secondary market doesn't develop, thus reducing the overall benefits of the scheme.

Complications with defining competitive hubs

1067. At first glance, the proposed method for defining hubs with adequate competition seems relatively simple. In practice the issue is likely to be relatively complex to address.

1068. For example, one of the concerns about competition is in regard to the ability of a local generator to set spot prices when circuits to a region are constrained. In these circumstances, several generators could be operating but nevertheless there may be only one generation unit that is the marginal supplier when the grid is constrained. Hence, the second condition for defining a competitive hub – that there are at least two competing generators in the hub – will need to be carefully applied.

1069. The first condition for defining a competitive hub was that all nodes in a hub exhibit similar price levels, after adjusting for marginal losses. The notion of "similar price levels" will need to be carefully defined. For example, over what time period would the price levels be defined, and what price gap would be considered similar?

1070. Adjusting for marginal losses would require significant modelling, which would need to be repeated on a regular basis to check that nodal price differences remain within the hub criteria.

1071. Once established, the boundaries for competitive hubs will need to change as new generators enter and exit the market. Market conditions will need to be monitored, and a rigorous and open process adopted for reassessing hub boundaries. With the large commercial value at stake for generators, inconsistent application of hub definitions over time could affect generator entry and exit decisions, carrying significant dynamic efficiency costs for the industry.

1072. As the distinction between auctioned FTRs and pre-allocated FTRs involves significant value transfers, the precise definition of hubs is likely to be controversial and perhaps hotly contested. Significant resources are likely to be expended by both the Commission and market participants on this issue.

Complications with defining pre-allocated FTRs

1073. Having deemed nodes outside of competitive hubs to have inadequate competition, it is then necessary to define the pre-allocated FTRs provided to them. For example, will the pre-allocated FTR represent claims to rentals from the nearby hub to node, or from some national or island average?

1074. Appendix E of the Read Report discusses several options in this regard, where it is clear that complications are likely to arise when a node is served by circuits from multiple hubs.

1075. Once pre-allocated FTRs are appropriately defined, new systems would need to be implemented to administer the assignment of pre-allocated FTRs, and to make FTR payments to those parties.

Revenue adequacy

1076. As outlined in the specification of this initiative, paragraph 989, revenue adequacy is an important objective for FTR regimes. Although the specification described in this paper includes two steps, simultaneous feasibility test and the scaling of payouts, to deal with revenue adequacy issues, regular revenue adequacy failures would reduce the value of FTRs as a tool for managing locational risk.

1077. In practice, revenue adequacy issues normally occur as a result of planned outages with a short notice period or unplanned outages. Historically, these events would not have seriously impacted revenue adequacy over the duration of long-term FTRs and does not appear to be a major issue for the implementation of this initiative. If serious issues did arise the Commission could introduce incentives for Transpower to minimise and improve planning of outages that have a pricing impact.

7.3.7 Conclusions

Timeframe for implementation

1078. The highly technical nature of the hybrid FTR initiative will require development of a suite of complex new rules, requiring at least two rounds of consultation. Completing this phase would take 24 – 30 months, and another 18 months would probably be required to implement the IT elements of the regime and test them. The overall timeframe for implementation is therefore in the order of 3.5 – 4 years.

Certainty of net economic benefits

1079. One of the major benefits of FTRs is that they are a well-established methodology that has been successfully implemented in several jurisdictions, particularly in America. Some of those jurisdictions, such as in the New York and New England markets, have implemented FTRs covering both losses and constraints, and so there is considerable international expertise available to advise local parties on technical implementation and market participation issues.

1080. Another major benefit of the hybrid FTR initiative is that it should facilitate more efficient management of locational and energy price risks with very minimal distortions to marginal pricing signals, and indeed should greatly improve the efficiency of those signals.

1081. The main concern with the initiative is the high participation costs, and corresponding risk of low participation. Another significant concern with the hybrid FTR initiative is determining which regions or nodes exhibit inadequate competition, defining those regions, and determining how to pre-allocate FTRs to spot market purchasers in those regions. These concerns, along with the high cost of implementing and administering the whole regime, suggest that there are considerable net benefits, but that the proportion of gross benefits taken up by costs is greater in New Zealand than in larger economies because administrative costs are relatively high due to the absence of scale economies.

Overall conclusion

1082. The key issue is whether the hybrid FTR initiative is likely to produce net economic benefits greater than the LRA approach. The comparative evaluation of both initiatives is presented in section 7.5.

7.4 Locational rental allocation

Overview

The LRA initiative presented in this section is embryonic, as relatively little time has been available to develop it compared to the amount of domestic and international effort put into developing FTR markets and products over the years. The LRA initiative is put forward in an effort to overcome the impasse on FTRs, but further work would be required to finalise the regime.

The LRA initiative allocates rentals to spot market purchasers in proportion to their locational price risk, as the largest value of rentals would be allocated to purchasers facing the highest nodal price differences and purchasing the largest quantity of energy at those prices.

The main problem with the LRA initiative is that inaccuracies in the allocation methodology could provide the wrong rebates for spot market purchasers and achieve fewer efficiency gains than promised. Another key problem is that the initiative reduces the efficiency of spot pricing signals for price-taking consumers, and probably also for other small consumers (although it should improve the efficiency of price signals for large consumers).

The net economic benefit of the LRA initiative is likely to be large and positive, as the baseline case is a situation where parties facing significant locational price risks have no means for hedging those risks on “imported” power. This situation appears to be critically stalling further evolution of the transmission and energy risk management markets.

Nevertheless, the key issue is whether the initiative is likely to produce greater net economic benefits than the hybrid FTR initiative. The comparative evaluation of both initiatives is presented in section 7.5.

7.4.1 Introduction

1083. The background discussion in section 7.1 explained that progress for introducing FTRs in New Zealand was fraught with widespread industry disagreement and stalled in 2003. Both the LRA and hybrid FTR initiatives are intended to address the underlying problems identified in section 7.2: lack of firm access to rentals and concerns about regional market power in the spot market.

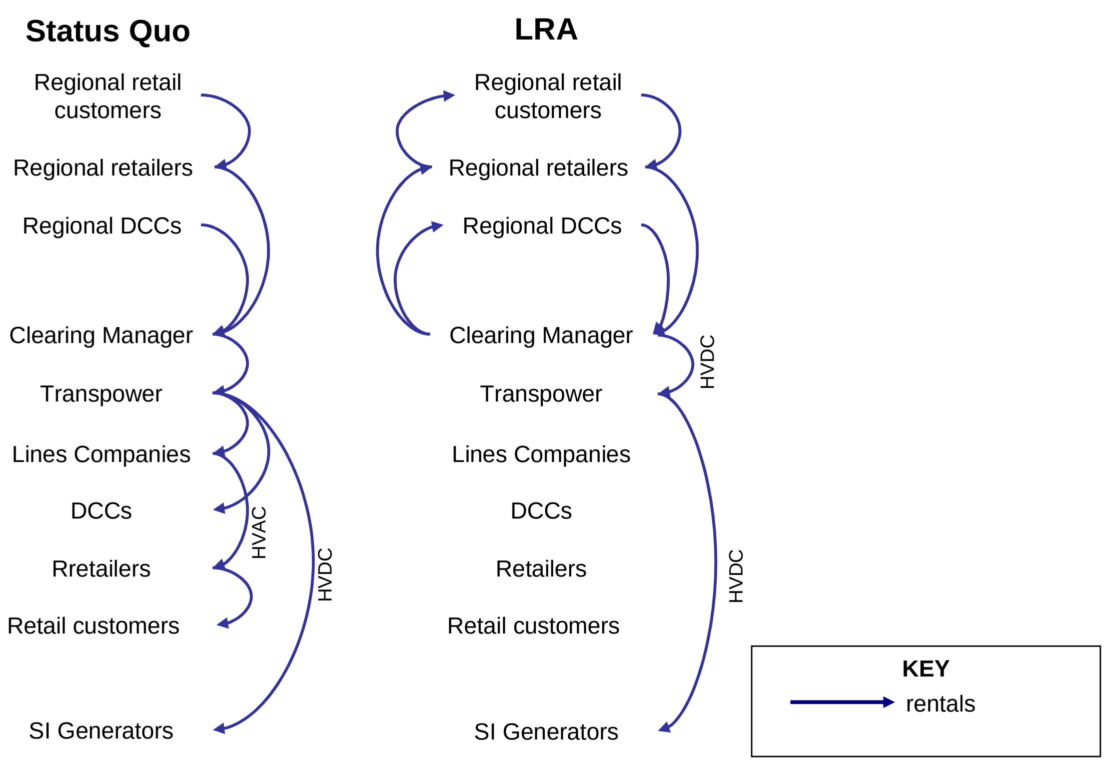
1084. The LRA initiative presented in this section is embryonic, as relatively little time has been available to develop it compared to the amount of domestic and international effort put into developing FTR markets and products over the last 5 years. The LRA initiative is put forward in an effort to overcome the logjam on FTRs, but further work would be required to finalise the regime.

1085. The objective of the LRA initiative is to rebate rentals to spot market purchasers in ways that mitigate their average locational price risk whilst minimising distortions to marginal pricing signals. In general, the largest value of rentals would be allocated to purchasers facing the highest nodal price differences and purchasing the largest quantity of energy at those prices.

1086. Although the initiative is relatively simple in conceptual terms, the practical details of the regime are highly technical. The specification of the initiative is therefore presented in two sections: a high-level specification in section 7.3.3 and a technical description in Appendix F.

1087. Figure 32 illustrates the nature of the money flows under the status quo and the LRA initiative. The diagram shows that the LRA initiative returns the HVAC rentals back to regional consumers, leaving them in aggregate paying zero average price differences between the nodes that are upstream and downstream of a constraint. The status quo spreads the rentals nationally to all consumers which, without FTRs, leaves regional consumers without any mechanism to manage their locational price risks.

Figure 32: Comparison of money flows for the status quo and LRA regimes



1088. A complication to the LRA methodology is that the HVDC rentals are provided to South Island generators, as they pay the HVDC charges. If the HVDC rentals were used to auction FTRs then the LRA column would include dashed lines to indicate the FTR payment flows.

1089. The LRA initiative will require the Commission to develop and administer new rules, and to also contract a service provider to operate and administer the process for allocating LRA rentals.

7.4.2 Promoter's view

Key problems

1090. A key problem identified in section 3.3.4 was the lack of suitable instruments to manage locational price risk. The promoters of the LRA initiative believe it effectively addresses this problem by allocating rentals to spot market purchasers paying high nodal price differences, directly reducing their locational price risks. They believe the rental allocation methodology can be designed to finely target the rental rebates to the parties facing locational price risk, and that any under or over allocation of rentals is either likely to be small or likely to provide the basis for parties to securitise those revenue streams and offer locational risk management instruments to the market.

Possible economic rationale

1091. In theory, any party can offer locational risk management contracts to smooth fluctuations in nodal price differences. In practice, few parties are willing to do so for "imported" power flows as the risks are highly dependent on Transpower's decisions about the way it operates the grid and on the offering strategies of generators operating behind the constraints. Hence, some form of central allocation of loss and constraint rentals is needed to address locational price risks: the LRA initiative is one option, and the hybrid FTR initiative is another.

1092. The economic rationale for the LRA initiative rests on the view that it is more efficient to centrally allocate the rentals and allow rental recipients to securitise and sell those rental flows if they wish (the LRA approach), than to securitise the rentals and centrally auction them to market participants (the FTR approach). The economic rationale for the LRA approach rests on the view that it avoids the high costs associated with parties participating in FTR auctions, it efficiently deals with regional market power problems, and it corrects some very large price distortions for large consumers.

7.4.3 High-level specification of the initiative

1093. A suite of new rules would be needed to define the LRA regime. The rules would need to specify what rentals are to be rebated, who would receive the rebates, when they would receive them, how much they would receive, and who would administer the regime.

1094. The rest of this section provides a high level description of the initiative, with the mathematical description of the allocation methodology presented in Appendix F. The specification provided below is very preliminary at this stage, and would require considerable further development and further consultation before being finalised. The paper discusses alternative specifications on some points where they are important to conducting the economic cost-benefit evaluation.

The total pool of rentals

1095. The pool of rentals available for allocation under the LRA initiative ("LRA rentals") would be only those rentals associated with components of the transmission grid for which the costs are recovered by interconnection charges. Under the current transmission pricing methodology, the interconnection charge covers the costs of HVAC assets other than connection assets.

1096. This approach means spot market purchasers receive rentals only for the part of the interconnected grid paid by lines companies, as lines companies pass those charges onto spot market purchasers. Although this approach leaves spot market purchasers exposed to locational price risks on the HVDC, South Island generators would be able to auction FTRs to cover those risks and would be free to rebate the HVDC rentals to parties paying for the HVDC.

Allocation of rentals

1097. The total pool of LRA rentals would be allocated to spot market purchasers on a nodal basis. Rentals would be allocated to spot market purchasers only if they are located at an eligible node. For a simple case, with only one constraint binding, this is any node, n, for which the price at that node, P_n, exceeds the price at a reference node, r. That is, eligible nodes are nodes for which $P_n > P_r$. Spot market purchasers at other nodes would not receive any rentals.

1098. In very simple terms, the methodology for calculating the rental rebate to a spot market purchaser is of the form:

Rebate = (nodal price – reference price) x purchaser's gross load x scale factor

1099. The above rebate is for only one trading period. The total monthly rebate for a spot market purchaser is therefore an aggregation of the half-hourly rebates.

1100. The scale factor on the right-hand-side of this formula equals total LRA rentals divided by the total "hedging requirement" of spot market purchasers for which $P_n > P_r$. The scale factor is used to ensure total rental allocations match the available rentals.

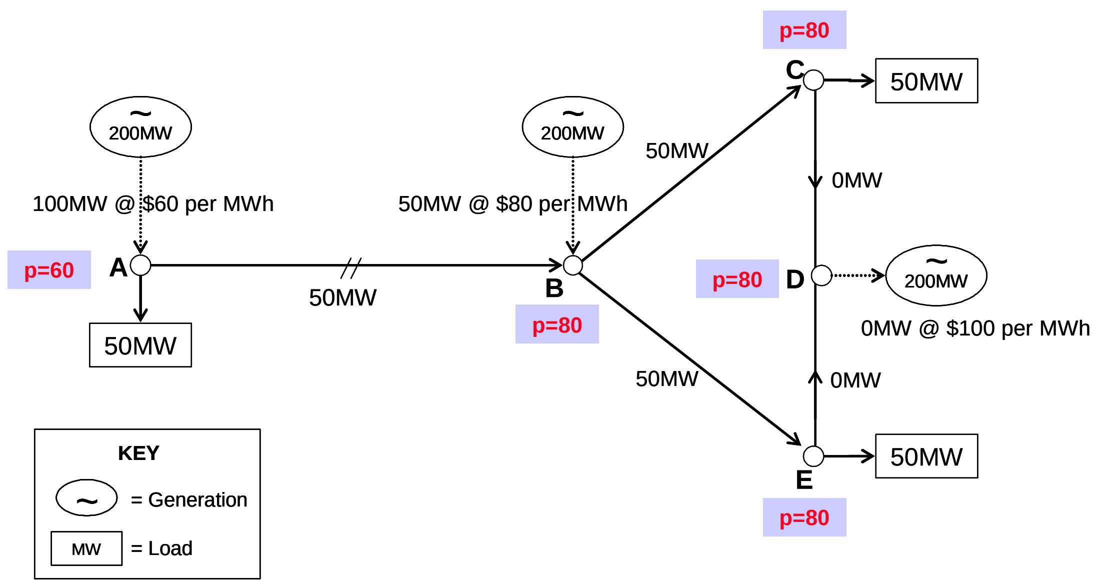
1101. The above formula allows rentals to be spread thinly across many nodes by setting a low reference price, P_r. Alternatively, rentals can be concentrated to the nodes most affected by locational price risk, by setting a high reference price. These issues are discussed further in section 7.4.4.

Numerical example

1102. The rationale for the allocation methodology is presented below using a simple numerical example illustrated in Figure 33. The hypothetical grid in this example has the following configuration:

- *The grid* – the grid comprises five nodes (A, B, C, D, and E) and all circuits are assumed to have equal impedance;
- *Load* – there is a total load of 150MW, distributed as follows: 50MW at node A, 50MW at node C, and 50MW at node E; and
- *Generation* – there are three 200MW generators on the grid: a generator at A offering into the market at $60 per MWh, a generator at B offering into the market at $80 per MWh, and a generator located at node D offering into the market at $100 per MWh.

Figure 33: Example Grid: AB constrained



1103. All circuits have equal impedance, and losses are therefore ignored. If circuit AB has a security-constrained capacity of 50MW, then:

- the cheapest generator, A, is dispatched to 100MW at $60 per MWh, thus meeting local load with a 50MW transfer to B;
- generator B, the cheapest downstream of the constraint, is dispatched to 50MW at $80 per MWh, meeting all remaining requirements at nodes in the BCDE loop;
- generator D is not dispatched because it is too expensive;
- thus the price is $60 at A, and $80 throughout the BCDE loop; and
- the rent generated on the AB constraint is 50MW x ($80 – $60) per MWh, or $1000 per hour.

1104. Intuitively, the rents on AB should be allocated to loads in loop BCDE, as they are the parties experiencing adverse locational price differences.

1105. The choice of reference node or reference price, P_r, is quite simple in this case. It can't be in loop BCDE, because all loads there face the same (high) price. Thus node A seems like the only option because it is the minimum price with respect to which loads in BCDE are "disadvantaged." Hence, P_r = $60 in this example.

1106. In this example, (P_n - P_r) = $20 for all nodes in region BCDE, and the total BCDE load is 100MW, so the "total hedging requirement" of BCDE is $2000. With total rentals equal to $1000, the scale factor is $1000/$2000 or 0.5.

1107. The rental rebate to load at C is ($80 - $60) x 50MW x 0.5 = $500. The same rebate is provided to load at E in this example as it has the same price differential and the load volume. Appendix F provides numerical examples where the price differentials and load volumes vary by node.

1108. Hence, the allocation methodology provides aggregate cover for 50 percent of the potential hedging requirement in the BCDE region. This is achieved because it uses the rents collected on "imported" power, which equal 50 percent of total load in region BCDE.

In practice

1109. The above example considered the simple case where there is a single grid constraint, no spring washer effects, and no losses. Relaxing these assumptions means that prices are not the same for all nodes downstream of the constraint. The technical version of the methodology deals with these complications by using participation factors, rather than prices, in the allocation formula.

1110. The concept of participation factors is rather technical, but in simple terms the participation factor for a node represents the implicit price impact that a circuit constraint has on the price at that node. If there are multiple constraints affecting prices at a node, then the participation factors for that node identify the price impact of each constraint. Appendix F explains the concept of participation factors further, and provides the technical details for the allocation methodology.

1111. The technical version of the allocation methodology can be expressed as:

Rebate = constraint shadow price x (participation factor – reference participation factor) x gross load x scale factor

1112. Note, the above rebate is for only one grid constraint. The total rebate for each half-hour trading period is the aggregation of rebates across all constraints occurring within the trading period. The total rebate for each month is an aggregation of the half-hourly rebates.

Administration and compliance arrangements

1113. In regard to administering the LRA regime, either the System Operator or the Pricing Manager could calculate participation factors using the SPD model. The rebates for each spot market purchaser could be calculated by the Clearing Manager using the data it has on reconciled load at each GXP. This function would integrate well with the Clearing Manager's current role of calculating monthly loss and constraint rentals.

1114. Rebates would be "paid" to spot market purchasers on a monthly basis. As the Clearing Manager invoices spot market purchasers for their energy purchases from the spot market, an integrated approach could be adopted where the Clearing Manager rebates the rentals by deducting the rebated amounts from the invoices it issues to spot market purchasers.

1115. Wash-ups in the spot market will impact on the amount and allocation of rentals. Consequently, the Clearing Manager will be required to calculate wash-up amounts in relation to rentals. In accordance with the Regulations, participants will have the ability to challenge the rentals calculation by alleging a breach of the Rules against the Clearing Manager.

Provision of historic information

1116. To assist generators and purchasers to assess the value of the hedging provided by the rental rebates, the Clearing Manager would publish three years of monthly historic information at node level for:

a. mean nodal spot energy prices;

b. participation factors; and

c. rebates allocated (or that were or would have been allocated) according to the methodology adopted.

1117. The calculation and publication of the historical information will enable purchasers to factor-in the average locational effect into their retail contracts, in the knowledge that there will be some rebate of rentals in the future.

7.4.4 Discussion of key aspects of the methodology

1118. The above description of the LRA methodology has been presented at a very high level, with minimal attention to detail, but the detail matters for evaluating the economic effects of the initiative. This section discusses key "policy" choices regarding the methodology, covering:

- the choice of reference price, which determines how thinly rentals are spread across the nodes;
- whether net or gross load should be used, which affects the value of rentals allocated to load parties with generation capability; and
- whether load should be lagged or fixed in some way to minimise any adverse effects on nodal price signals.

The choice of reference node, r

1119. The choice of reference node is critical to the economic effects of the LRA initiative, in terms of both hedging effectiveness and economic efficiency. Broadly, the choice lies between choosing the node with the lowest participation factor, the node with the highest participation factor, or something between these two extremes.

1120. Selecting the reference node to be the one with the lowest participation factor, r_{min}, would allocate some rentals to all spot market purchasers, including those who experienced low (but not the lowest) prices as a result of grid constraints. From a risk management perspective, it doesn't make sense to allocate rentals to parties benefiting from grid constraints.

1121. Alternatively, selecting the node with the highest participation factor, r_{max}, would allocate all rentals to the reference node, and none to anyone else suffering high prices from the constraint. This is clearly too extreme, and will often reduce effective prices at those nodes below effective prices at many other nodes.

1122. As grid constraints increase downstream prices and depress upstream prices, an intuitive choice would be a reference node at which the pricing impact of a constraint might be considered to be "neutral". If only one constraint binds, this corresponds to choosing a reference node corresponding to the load-weighted average price (LWAP) for each trading period. Another alternative would be the generation-weighted average price (GWAP), which is less than the LWAP but generally greater than r_{min}. Either of these options is likely to be more efficient and effective than r_{min} or r_{max}.

1123. For the purposes of the economic evaluation below, we assume the reference node is a notional node corresponding to the LWAP for each half-hour trading period.

Gross or net load

1124. The allocation methodology uses gross rather than net load to allocate rentals to spot market purchasers. This means:

a. two spot market purchasers with the same load levels and located at the same node will receive the same rental allocation even if one of them is fully or partially hedged with its own generation; and

b. similarly, two purchasers with the same load levels and facing the same nodal prices will receive the same rental allocation even if one of them is located at a node where there is also generation and the other is located far away from generation.

1125. The intuition for the gross approach can be explained by considering the situation in Figure 33, where there is only one constraint in the system, and no losses and no spring washer effects. In this case the grid constraint equally affects all nodal prices downstream of the constraint, creating a pool of spot market purchasers exposed to the same fluctuations in nodal prices. In this simple example, parties that don't receive enough rentals to cover their locational price risks can purchase hedge cover from spot market purchasers with excess rentals or from local generators.

1126. Under these assumptions, parties that supply their own generation (as in paragraph 1077a above) are in effect providing hedge cover for all spot market purchasers in the constrained region, because their generation depresses locational price differences for everyone in the loop. Moreover, allocating rentals in proportion to gross load facilitates efficient risk management because the allocation methodology doesn't discriminate between self-supply of hedge cover or purchase of hedges from the market.

1127. Similarly the methodology doesn't discriminate between load located at the same node as generation and load located near to generation (paragraph 1077b above). As they are all located within the same price pool, economic efficiency requires them to be treated the same in terms of rental allocations so that load parties make location decisions within the constrained region based on the economic advantages of one location versus another, rather than based on differences in rental allocations.

1128. The same logic applies in the complicated case where there are different prices at each node due to losses, spring washer effects, and multiple constraints. This is because the participation factors in the allocation methodology separate the price effects into their component parts.

Contemporaneous, lagged, or fixed load shares

1129. Another important policy choice is whether contemporaneous, lagged, or fixed load shares should be used in the allocation methodology. The above formulation assumes contemporaneous load shares would be used.

1130. Under the contemporaneous approach there is a strong positive correlation between high nodal price differences and total rent available for allocation. When nodal price differences are high, spot market purchasers know that any reduction in electricity consumption saves them the high nodal price but loses them significant rental allocations. Consequently, the effective price they pay for power is lower than the nodal price they pay in the market. As explained in section 7.1.4, this can be good or bad for economic efficiency but is clearly good for providing spot market purchasers with cover against locational price risk.

1131. Alternative approaches would be to lag load by a month, or a year, or use annual load shares. Although each of these options would weaken the impact on marginal pricing signals, they would also undermine the hedging value obtained from the LRA initiative. Appendix F discusses these issues in greater detail.

1132. The contemporaneous approach has been adopted in this paper to exaggerate the difference between the LRA and hybrid FTR initiatives, and to simplify the evaluation of the LRA initiative.

7.4.5 Impact on locational price risk and pricing signals

1133. Before discussing the potential costs and benefits of the initiative, it is necessary to determine the impact the allocation methodology has on locational price risk and pricing signals arising from the spot market and transmission pricing.

Impact on locational price risk

1134. In principle, the impact on locational price risk is relatively straight forward. As the LRA rentals exclude HVDC rentals, the initiative doesn't cover locational price risks relating to HVDC power flows. It also doesn't cover locational price risk relating to local generation, as rentals only accrue on power flows “imported” to a region.

1135. In both cases, though, other parties should be willing to provide transmission risk management contracts covering these risks. For example, Transpower would have access to the HVDC rentals and so could auction FTRs for the HVDC or the recipients of the HVDC rentals could issue their own transmission risk management contracts. Likewise, generators with local plants should have the capacity to issue transmission risk management contract to cover load served by local generation.

1136. The choice of reference node affects the apportionment of rentals among nodes, but doesn't affect the overall volume of rentals allocated under the initiative. As stated earlier, we assume the reference price equals the LWAP for each half-hour. Under this approach, some rentals may be provided to spot market purchasers at depressed nodes, leaving spot market purchasers at elevated nodes with smaller rental volumes than needed to cover their residual locational price risks.

1137. Conceptually, reference nodes ought to be able to be chosen to ensure the initiative provides sufficient cover for the residual locational price risks faced by spot market purchasers. This is unlikely to occur in practice, but the extent of departure is difficult to gauge at this stage and depends critically on the choice of reference node.

Potential impact on spot price signals

1138. The efficiency of spot market price signals was outlined in section 7.1.4, where it was shown that second-order effects mean that spot prices provide excessive incentives for consumers to reduce load when, in the presence of grid constraints, their individual consumption choices influence nodal prices.

1139. This was shown by calculating the effective incremental price for a small consumer increasing its load from 10MW to 20MW, and for a large consumer increasing its load by 100MW to 110MW. Both consumers were assumed to be completely unhedged. The table summarising the results of the example is repeated below.

Figure 34 (Figure 27 repeated): Effective price signals with no rebates

	Efficient Signal	No Rebates	
	Price-taking Consumers	Small Consumer	Large Consumer
Marginal Price ($/MWh)	50	50	50
Effective Incremental Price ($/MWh)	50	90	450
Gain from 10MW grid expansion ($)	400	800	4,400

1140. The LRA initiative partially corrects these excessive incentives. Under the LRA initiative consumers know that if their actions are likely to alter spot market prices, the second-order effects they experience when prices change are partially offset by changes in the value of rentals allocated to them.

1141. The impact on spot pricing signals is easiest to calculate by first considering the case where the reference price can be set perfectly, and contemporaneous load shares are used, so that rentals are only allocated to nodes with positive participation factors.

1142. Assume, to start with, that rentals account for 50 percent of the total hedging requirement of spot market purchasers (i.e., the scale factor = 0.5). To calculate the total hedging requirement for the two consumers, assume that only one of them increases load by 10MW at any one time, so that total load is 120MW when prices increase from $10 to $50. Then the total hedging requirement is 120MW x $40, which is $4,800, and so the total value of the rentals is $2,400.

1143. To calculate the effective incremental price for the large consumer, assume it increases its load from 100MW to 110MW and the small consumer has 10MW of load. Under the LRA initiative, the large consumer receives 91.6 percent of the rentals, as its load accounts for 110MW of the total 120MW of consumption when the constraint binds. This amounts to $2,200.

1144. Recall from the example for Figure 25 in section 7.1 that the second-order effect was $4,000 for the large consumer. Hence, the large consumer pays an additional $2,300, comprising $4,000 of second-order effects, plus $500 for the additional 10MW of load at $50 per MWh, less $2,200 of rentals. The effective incremental price for the large consumer is therefore $230, which is considerably lower than $450 in Figure 25.

1145. Similar calculations for the small consumer produce an effective incremental price of $50. This arises because the small consumer pays $400 of second-order effects, plus $500 for the additional 10MW of load, less $400 of rentals. The rentals in this case exactly offset the value of the second-order effect, leaving the small consumer with the efficient marginal price signal.

1146. The above results are sensitive to assumptions about the value of rentals as a share of the total hedging requirement of spot market purchasers. If the scale factor is 90 percent then the rentals provided to the large consumer largely offset their second-order effect, leaving it with an effective incremental price of only $54, which is close to the efficient price signal. On the other hand, the rentals provided to the small consumer in this case exceed their second-order effect, leaving it with an effective incremental price of $18, which is less than the efficient price signal.

1147. These results are summarised in the two right-hand-side columns of Figure 35 below. Note that under both the 50 percent and 90 percent scenarios the LRA initiative distorts price signals for price-taking consumers. This occurs because the LRA pays rentals to price-taking consumers even though they face no second-order effects. This is shown in the left-hand-side column of Figure 34.

Figure 35: Effective price signals under the LRA initiative

Effective Incremental Price	Price-taking Consumers	Small Consumer	Large Consumer
No rental rebates - Table 8.1 ($/MWh)	50	90	450
LRA with rentals equal to 50% of total hedge requirements ($/MWh)	30	50	230
LRA with rentals equal to 90% of total hedge requirements ($/MWh)	14	18	54

1148. The above results are artificial because the analysis has been conducted on the assumption that consumers are completely unhedged. In practice, consumers are likely to obtain some hedge cover from generators to cover load served by local generation. As shown in Figure 28, this has the potential to further improve the effective incremental price signal for the large consumer without worsening it for the small consumer or for price-taking consumers.

1149. In principle, the LRA initiative improves the efficiency of price signals for large consumers and reduces the efficiency of price signals for price-taking consumers. The efficiency implications are not so clear-cut for small consumers able to influence nodal prices. In the examples used above, the effective incremental price to small consumers swings from being excessive ($90) to being too low ($18).

Actual impact on spot price signals

1150. The actual impact on price signals depends on how effectively the hedge market works, and on the extent which the LRA methodology departs from the optimal one. An FTR market for the HVDC should be relatively competitive, so it should work well. Likewise, generator/retailers should face strong incentives to issue contracts against their local generation when their local generation is likely to exceed their local retail load.

1151. Imperfections in the LRA methodology are likely to arise from making pragmatic choices about key parameters discussed in section 7.4.4 and in Appendix F. These imperfections are likely to result in the rental allocation failing to provide sufficient rentals to fully cover locational price risk on imported power. As a result, some large spot market purchasers may face excessive marginal pricing signals, although it is highly likely pricing signals will be significantly better than under a no-rebate or flat rebate methodology. On the other hand, price-taking consumers are highly likely to face distorted price signals. It is possible that this price distortion may offset the price distortion from the recovery of some fixed transmission and distribution costs on a variable basis in distribution tariffs.

7.4.6 Potential Economic Benefits

1152. The potential benefits of the initiative depend on:

a. whether the initiative facilitates more efficient management of locational price risk;

b. whether the developments in (a) flow through to more efficient levels of liquidity in the energy contracts market;

c. the extent to which the initiative leaves flexibility for other parties to introduce alternative or complementary transmission risk management instruments;

d. whether the initiative affects barriers to entry in the retail electricity market;

e. how the initiative affects consumption decisions;

f. whether generators have the ability to game the spot market and, if so, whether the initiative reduces those incentives; and

g. whether the initiative reduces incentives for unproductive lobbying for, or against, transmission investment proposals.

More efficient management of locational price risk

1153. Allocating HVAC rentals to the participants that effectively paid the rentals is a very direct method of allowing them to manage a significant component of their locational price risk.

1154. As a result, the LRA initiative has the potential to provide parties exposed to locational price risks with additional options to choose energy and transmission risk management products that best suit them. For example:

- As load parties located near the main generation hubs can use bundled contracts to manage their locational price risk, the initiative provides them with an additional option for managing those risks. This should be efficiency enhancing, as generators and consumers can continue to use bundled contracts if they are a more commercially advantageous option for managing those risks.
- As load parties distant from the main generation hubs currently have very limited options for managing their locational price risks, the initiative should achieve significantly more efficient management of those risks. This will be particularly the case if rental recipients can easily securitise any rentals they receive and offer them to parties with rentals.

1155. Similarly, if retailers distant from the main generation nodes can rely on rental allocations and transmission risk management contracts to cover their locational price risks, they may find these options are cheaper and more flexible than owning local generation plants. In these circumstances, generator/retailers will choose vertical integration in constrained regions only when doing so provides a more efficient tool for managing their locational price risks.

Increased certainty for purchasers

1156. Another key advantage of the LRA initiative is the increased certainty that purchasers have in relation to transmission hedging. LRAs would effectively provide long-term hedge cover for all purchasers. This is because the methodology would be clearly defined and would not change significantly over time.

More efficient depth and liquidity in the energy contracts market

1157. If spot market purchasers more readily rely on rental allocations and transmission risk management contracts to manage their locational price risks, then energy contracts are likely to consolidate around one or two reference nodes, creating greater liquidity in the energy contracts market and greater standardisation of energy contracts. As any increases in market depth and liquidity occur voluntarily, they are likely to be efficiency enhancing.

Reduced barriers to entry in the retail market

1158. Relative to the baseline scenario, 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 the main generation nodes. New retailers might be wholly independent retailers, or vertically integrated retailers with generation located outside the constrained region.

1159. The LRA initiative reduces barriers to entry by allowing new retailers to access generation located upstream of grid constraints at upstream (i.e., lower) prices. This occurs because the higher downstream prices are partially offset by rentals allocated to load in the constrained regions. This offset is larger the greater that local load is served by “imported” rather than local power.

1160. The above analysis needs to be tempered by the amount of the residual risk new entrant retailers will be exposed to. For example, the choice of reference node may inhibit the reduction of retail entry barriers. If the reference price equals the LWAP, for example, the LRA initiative may provide insufficient rentals to new entrant retailers, leaving them exposed to purchasing additional cover from the transmission risk management market.

1161. As a result of reduced barriers to entry, the initiative is likely to lead to greater competition in the retail electricity market. Lower prices should result as retailers reflect the value of the rentals they receive in their retail tariffs.

More efficient consumption and investment decisions by large consumers

1162. Relative to the baseline scenario, the LRA initiative has the potential to improve the efficiency of large consumers' short-term consumption decisions, in regard to both demand smoothing and demand reduction activities. In practice, these efficiency benefits are likely to be relatively small as load is highly inelastic in the short-term (i.e., largely unresponsive to price signals).

1163. The more efficient pricing signals for large consumers in Figure 35 may, however, significantly affect their long-term consumption decisions, such as in regard to the overall magnitude, timing, and location of their investment in load and co-generation plant. Under the baseline scenario consumers face excessive incentives to invest in too much co-generation, to delay their load investments, and to locate their load in unconstrained areas of the grid. The efficiency gains from reducing these distortions may be large over the long term.

1164. For the same reasons, the LRA initiative may also significantly alter consumer participation in the reserves market. Consumer provision of reserves brings large wealth transfers to them, as it allows the grid to be operated to higher levels before grid constraints become binding. As some of the commercial gains and losses from participating in these markets affect the level of rental rebate, the LRA initiative better aligns commercial benefits with overall economic benefits.

1165. In practice, these efficiency gains will be tempered by inaccuracies in the rental allocation formula discussed above.

Reduced generator gaming incentives

1166. Generator incentives are the converse of the spot pricing incentives for consumers. Under the baseline scenario, generator/retailers with a net generation position in constrained regions may sometimes have incentives to game the spot market by adopting offering strategies that cause grid constraints to bind and prices rise at the local node. Converse incentives may arise for generator/retailers with a net retail position in unconstrained regions of the grid.

1167. The LRA initiative reduces these gaming incentives as the rental allocations partially offset the second-order effects discussed earlier in this section. To the extent gaming occurs under the baseline case, the LRA initiative would likely lead to more efficient spot pricing signals.

1168. These effects may be tempered somewhat if generators are currently constraining their offer prices to reduce the risks of the Government introducing price restraints of some form in reaction to consumer pressures. By allocating rentals to consumers facing the high spot prices, the LRA initiative may reduce generator concerns about possible price intervention.

Flexibility to adopt other approaches to managing locational price risk

1169. The LRA initiative presents a highly prescriptive methodology for allocating rentals, but is non-prescriptive about what spot market purchasers should do with them. In particular, 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 provides maximum freedom for innovation in the transmission risk management market.

1170. In particular, the LRA initiative poses no significant barrier to the development of other hedging mechanisms. For example, if there was industry interest in introducing FTRs for the core grid, that could be accommodated through a hybrid FTR and rentals allocation regime.

Reduced lobbying and litigation activity

1171. Relative to the baseline market, the LRA initiative greatly reduces the disparity between the commercial and economic benefits of transmission investment. This should reduce consumer and generator/retailer incentives to lobby for (or against) transmission investments purely for the large wealth transfers that would accrue to them (or against them). It should also greatly reduce incentives for parties to litigate such decisions.

1172. Lobbying and litigation activity is unproductive activity, as it does not contribute to producing *final* goods and services. The LRA initiative, therefore, frees up resources for other more productive activities.

7.4.7 Costs and risks

1173. The costs and risks of the LRA initiative depend on:

a. the extent the initiative distorts spot pricing signals for price-taking consumers, and in some respects for small consumers;

b. whether inaccuracies in the allocation methodology greatly distort the rental allocation, tempering the efficiency gains discussed above; and

c. the costs of developing, implementing, and administering the LRA methodology.

Less efficient short-term consumption decisions by price-taking consumers

1174. Although the LRA initiative should provide more appropriate locational incentives for small consumers (as discussed in section 7.4.5 above), it alters the effective spot pricing signals for price-taking consumers and for small consumers able to influence nodal prices.

1175. In regard to large consumers able to influence nodal prices, the LRA initiative swings the effective pricing signal from being too high to sometimes being too low (refer to the last row of Figure 35 above). In principle, then, it is difficult to determine whether the LRA initiative improves or worsens the efficiency of spot pricing signals for these consumers.

1176. On the other hand, the case is clear-cut for price-taking consumers. In this case the LRA initiative reduces the efficiency of the spot pricing signals for short-term consumption decisions, leading them to undertake too little demand-smoothing and too little demand reduction activity.

1177. Although price-taking consumers are far more numerous than large consumers, the vast majority of them are on fixed price retail tariffs and, therefore, are not exposed to any form of spot pricing signal. On balance we conclude the LRA initiative reduces the efficiency of price-taking consumers' decisions by a much smaller amount than it improves decision-making by large consumers.

Inaccuracies in the allocation methodology

1178. The LRA initiative may be less effective than discussed above due to inaccuracies in the allocation of rentals. It is difficult to determine at this early stage the extent of these inaccuracies. In principle, it is possible that some rentals may end up being allocated to participants trading at depressed nodes. To the extent these effects occur, they reduce the efficiency benefits of the initiative relative to that discussed above.

Implementation costs

1179. The cost of implementing the LRA initiative will be driven by the work required to create and agree the new methodology, and any IT development costs associated with changing the SPD model and reconfiguring the Clearing Manager's systems. Since the LRA methodology has not been employed anywhere else to date, and is still in an embryonic stage, the costs of its implementation are difficult to estimate.

1180. In practice, correctly identifying the appropriate attribution of rentals to specific locations is likely to be complex. In many respects these complexities will be similar or identical to pre-allocating FTRs to each location, and conducting the revenue adequacy and simultaneous feasibility calculations under the hybrid FTR option.

Administration and compliance costs

1181. The ongoing operation and administration of the LRA regime should be reasonably straightforward if the allocation task is integrated with the clearing and settlement systems operated by the Clearing Manager.

1182. Offsetting these costs will be reduced costs for Transpower and distribution companies as they no longer need to administer the distribution of interconnection rentals to retailers and large consumers, although they will still need to distribute any connection rentals they receive. The ongoing administration and compliance costs may, in fact, be lower than under current arrangements, but for the purposes of this analysis we assume the costs are higher by a small amount.

7.4.8 Conclusion

Timeframe for implementation

1183. The highly technical and embryonic nature of the allocation methodology will require development of a suite of complex new rules, probably requiring at least two rounds of consultation. The consultation in each case will need to be extensive due to significant wealth transfers from allocating rentals to spot market purchasers rather than lines companies and from allocating the rentals on a regional rather than nationwide basis. Completing this phase would take 24 – 36 months, and another 12 months would probably be required to implement the IT elements of the regime and test them. The overall timeframe for implementation is therefore in the order of 3 – 4 years.

Certainty of net economic benefits

1184. One of the major benefits of the LRA initiative is that it should facilitate more efficient management of locational and energy price risks. There should also be significant benefits from ongoing evolution of the two risk management markets, as allocating rentals to spot market purchasers leaves it to them to decide how to participate in those markets. The LRA should also improve the efficiency of decision-making for large consumers, and reduce incentives for them to unproductively lobby for, or against, transmission investment proposals. The benefits are less certain in regard to reducing barriers to entry to the retail market, and in regard to reducing gaming incentives for generator/retailers.

1185. The primary cost of the LRA initiative is likely to be in creating an appropriate allocation formula and undertaking the necessary IT development costs to implement the regime. While there may be some costs from distorting spot pricing signals for price-taking consumers, many of them don’t face spot pricing signals anyway.

1186. Overall, then, the economic benefits appear to be numerous and far greater than the costs of implementing the initiative.

Overall conclusion

1187. Unlike other new and complex initiatives presented in this consultation paper, the net economic benefit of the LRA initiative is likely to be large and positive. This is because the baseline case is a situation where parties facing significant locational price risks have no means for hedging those risks on “imported” power. This situation is critically stalling further evolution of the transmission and energy risk management markets.

1188. Nevertheless, the key issue is whether the LRA approach is likely to produce net economic benefits greater than the hybrid FTR approach. The comparative evaluation of both initiatives is presented in section 7.5.

7.5 Comparative evaluation of transmission risk management initiatives

Overview

This section provides a comparative evaluation of the LRA and hybrid FTR initiatives to determine which is likely to produce the largest net economic value for New Zealand.

Determining the highest value option depends on views about regional market power, participation costs, and the practicality of determining which parts of the grid have inadequate competition.

On balance, the HMDSG believes the LRA initiative is likely to produce the largest net economic benefits because regional market power is a significant constraint on auctioning FTRs, and participation costs are likely to be high. Also, significant complications arise in determining which nodes and regions are competitive and which are not. This leads into difficulties with pre-allocating FTRs.

Although both initiatives improve the efficiency of spot pricing signals for large consumers, the LRA initiative distorts spot pricing signals for price-taking consumers, and perhaps also for small consumers. In reality, many small consumers have FPVV contracts and are not exposed to spot price signals. The HMDSG believes these efficiency losses are likely to be less than the costs associated with FTRs.

7.5.1 Introduction

1189. The previous sections evaluated the hybrid FTR and LRA initiatives against the baseline case in section 5 of the paper. Both evaluations indicated large net economic benefits were likely from implementing either initiative, as they both provide effective means for spot market purchasers to manage locational price risks.

1190. This section compares the two initiatives to determine which is likely to produce the largest net economic benefit for New Zealand. Section 7.5.3 outlines similarities between the two initiatives in regard to their economic effects while section 7.5.4 discusses the key differences between them. Section 7.5.5 provides an overall conclusion.

7.5.2 Similarities between the two initiatives

Locational price risk

1191. Both initiatives provide aggregate cover for locational price risk on “imported” power, but leave it to spot market purchasers to obtain energy and locational contract cover from local generators in order to be fully hedged. If there really is a regional market power problem, then some spot market purchasers may be reluctant to purchase these contracts from local generators. This could mean that neither initiative fully addresses the problem identified in section 3.3.4 regarding the lack of effective instruments for managing locational price risk.

1192. At the individual level, both initiatives are unlikely to target rentals to those spot market purchasers most exposed to locational price risk. For example, the specification in section 7.3 assumes that auctioned FTRs would be defined in relation to approximately 20 trading hubs, rather than in relation to individual nodes.

1193. Moreover, the auction approach allocates monthly rentals to parties that bid the highest prices at the auction. Although, in theory, the highest bidders should be the parties with the highest locational price risks, in practice the complexities of predicting spot prices and the prospect that some bidders may have market power in the spot market, may undermine the desired outcome. This introduces greater uncertainty regarding access to rentals for any individual auction participant.

1194. The pre-allocation of FTRs introduces further arbitrariness, as definitions of competitive and uncompetitive parts of the grid are likely to change over time as generator entry and exit occurs, and as demand-management technology changes. Defining and re-defining the non-competitive parts of the grid is likely to be controversial each time it arises, introducing further uncertainty for investors and incentives for affected parties to lobby. Even assuming no market power, large organisations are likely to have an advantage when valuing FTRs because of the resources available to them.

1195. In contrast the LRA allocation methodology allocates rentals to each node based on each node’s participation factor for each half-hour. This methodology delivers a very finely targeted allocation of rentals based on the underlying locational price exposure as defined by gross load. Participants may gain added benefit as they have already offset some of their locational risk through a range of tools such as: local generation, load control, and derivatives.

1196. Overall, it appears both initiatives are likely to result in contentious value transfers among spot market purchasers. Nevertheless, either initiative would be an improvement over the status quo.

Marginal price signals for large consumers

1197. Both initiatives should substantially reduce the excessive marginal price signals identified in section 7.1.4 for large consumers. The hybrid FTR initiative is possibly more effective at doing so if large consumers are already well-hedged. As discussed previously, however, this is unlikely to be the case for the majority of large consumers. The LRA initiative should also substantially reduce the excessive marginal price signals for large consumers, but again this depends on how well hedged they are with their own generation and with other derivatives.

Other factors

1198. Both initiatives involve allocating rentals to the regions. Hence, similar administrative arrangements will be required for both initiatives in regard to auction and allocation algorithms and processes. There are some important differences in participation requirements, which are discussed in the next section.

1199. Both initiatives rely on effective retail competition creating incentives for retailers to pass rentals back to their customers, in the form of competitive tariffs. Likewise, both initiatives allow for the auction of FTRs on the HVDC part of the grid, and both pass HVDC auction proceeds to South Island generators.

7.5.3 Key differences between the two initiatives

Regional market power

1200. The most important difference between the two initiatives is in the way they deal with concerns about regional market power.

1201. The LRA initiative deals with the issue by avoiding it altogether, and allocating rentals to everyone on the basis of gross load and participation factors. Although technically obscure to most market participants, this approach has the advantage that it is based on market fundamentals embedded in the SPD model.

1202. In contrast, the hybrid FTR initiative requires the Commission or some other regulatory agency to make decisions about which parts of the grid have inadequate levels of competition. While very simple to state in theory, the practical implementation of the initiative is likely to involve difficult and subjective judgements about where to draw the line between competitive and non-competitive parts of the grid. This process is likely to be controversial and time-consuming.

1203. Furthermore, the competitive state of the grid changes as market participants enter and exit the market, which means the designation of non-competitive parts of the grid would need to be reviewed on a regular basis. Such reviews are also likely to controversial, time consuming and costly and in reality the preallocation of FTRs would only partly address perceptions of market power.

Hedge duration

1204. Another difference between the two initiatives is in regard to the duration of the risk management cover provided. The auctioned FTRs have only one month duration, at least initially, whereas longer duration FTRs (2-5 years) are likely to be required to provide adequate hedge cover to the retailing sector. In addition, FTRs do not provide any hedge cover for parties that are not successful in obtaining FTRs through the auction process.

1205. LRAs, and the allocated FTRs however, effectively provide long-term hedge cover for all purchasers. This is because as long as the allocation methodology is well understood all parties that face locational price risk will get some rentals allocated to them.

1206. While there are design differences between the two initiatives, auctioned FTRs may also become viewed as stable over time as the parties work out their optimal combinations of hedge cover and each bids accordingly.

Average locational price signals

1207. Another important difference between the two initiatives is their effects on average nodal price differences or gaps. Auctioned FTRs preserve the average price gap between hubs because FTR holders pay for their FTRs and receive rental allocations in return. If on average they bid the present value of the rentals then on average their net money transfer is zero. On the other hand, simply allocating the rentals to spot market purchasers closes the average nodal price gap.

1208. These considerations mean the LRA initiative reduces nodal price gaps on the HVAC, but retains the gap on the HVDC. The hybrid FTR initiative preserves much more of the average nodal gap throughout the grid, but where inadequate competition is deemed to exist, the initiative closes the gap by pre-allocating FTRs.

1209. The implication of this outcome is that the hybrid FTR initiative provides more efficient long-term location signals for all consumers than the LRA initiative. Relative to the status quo, the LRA initiative creates larger value transfers from consumers in areas with low levels of locational price risk to consumers in areas with high levels of locational price risk.

Marginal price signals for small consumers

1210. Section 7.5.3 suggested that both initiatives appear to improve the efficiency of spot pricing signals for large consumers. A key advantage of auctioning FTRs is that they preserve the efficiency of spot price signals for small consumers and price-taking consumers. The hybrid FTR initiative offers greater benefits in this respect, although the LRA initiative reduces the efficiency of spot price signals for small and price-taking consumers, although it preserves some signals by allowing for the auctioning of FTRs on the HVDC.

Participation requirements

1211. A key practical difference between the initiatives is their participation requirements. The hybrid FTR initiative requires spot market purchasers to actively participate in regular auctions if they wish to obtain cover against their locational price risks, which would require them to invest in modelling the factors determining nodal prices.

1212. In contrast, the complexities with the LRA initiative are centralised and contained in the allocation methodology. Participants only need to understand the methodology for infrequent situations where they wish to check they are receiving appropriate payouts. Although the LRA initiative allows for the auctioning of FTRs over the HVDC, the factors affecting HVDC price differences are much simpler than for the whole grid, and in any case HVDC FTRs are auctioned under both initiatives.

Secondary trading

1213. The hybrid FTR initiative defines and enforces claims to specific loss and constraint rentals, whereas the LRA initiative only does so for HVDC rentals. Hence, the FTR approach provides a ready basis for parties to trade their claims within a well-defined system, including arrangements for prudential security.

1214. In regard to HVAC rentals, the LRA initiative leaves it to rental recipients to securitise and trade their revenue streams. This approach provides a more decentralised trading outcome, where trading can evolve to meet the needs of market participants as and when they like. The freedom for rental recipients to trade their own FTRs is likely to facilitate innovation and achieve higher levels of dynamic efficiency. The systems required for the secondary trading of FTRs would present some significant implementation challenges and this should not be underestimated.

Pass-through obligations

1215. The LRA methodology uses the Clearing Manager to directly allocate HVAC rentals to spot market purchasers, whereas several other parties are involved in the hybrid FTR initiative (recall Figure 30). In particular, the hybrid FTR initiative requires obligations be placed on lines businesses to pass HVAC rentals to their customers in proportion to transmission charges.

International experience

1216. Another difference between the hybrid FTR and the LRA initiatives is that, whereas FTRs, including FTRs with pre-allocation, have been implemented in several places and their performance and properties are reasonably well known, LRAs are a new idea not yet fully developed or implemented anywhere. It is likely that a significant amount of work would be required to develop people's understanding of LRAs to the same level as FTRs.

7.5.4 *Conclusions*

1217. Below is a table that summarises the comparative evaluation discussion contained in section 7.5 of this paper.

Criteria	Importance	Hybrid financial transmission rights	+/-	Locational rental allocation
1 Aggregate locational price risk cover	High	Aggregate cover on imported power but require additional contracts to achieve a fully hedged position.	=	Aggregate cover on imported power but require additional contracts to achieve a fully hedged position.
2 Individual locational price risk cover	High	Defined at 20 trading hubs, rather than individual nodes, so unlikely to provide cover for those most exposed to locational price risk.	<	Utilises participation factors to allocate rentals to individual nodes but allocation by gross loads may distort final payments
3 Simplicity of allocation methodology	High	Requires contentious definition of non-competitive regions and creation of an auction infrastructure	=	Requires creation of a new participation factors methodology
4 Marginal price signals for large consumers	Medium	Should substantially reduce the excessive marginal price signals	=	Should substantially reduce the excessive marginal price signals
5 Regional market power	Medium	Requires the definition of regions that have inadequate competition.	<	Avoids issue by allocating rentals to everyone based on gross load and participation factors.
6 Hedge duration	Medium	Short to medium term hedge cover with uncertain renewal under an auction mechanism	<	Long term hedge cover with a regulated renewal mechanism
7 Average locational price signals	Medium	Preserves nodal price signals	>	Reduces nodal price signals
8 Marginal price signals for small consumers	Low	Preserves efficiency	>	Reduces efficiency
9 Participation requirements	High	High – Requires regular active participation in auctions and invest in modelling for valuation of FTRs	<	Low – Complexity contained in allocation model.
10 Secondary trading	Low	Provides a ready made product for secondary trading	>	Requires participants to securitise their revenue streams
11 Pass through obligations	Medium	Requires obligations on lines companies to pass through to end customer	<	Utilises the Clearing Manager to allocate rentals directly to spot market purchasers

1218. For each criteria outlined in the table above the +/- column gives the reader a visual representation of how the Commission believes the two initiatives compare. The notation that has been adopted is as follows:

Sign	Meaning
=	The two initiatives deliver similar benefits
<	LRAs delivers greater benefits than hybrid FTRs
>	FTRs deliver greater benefits than LRAs

1219. On balance, the HMDSG believes that the net economic benefits of the two initiatives are very close but that the LRA initiative is likely to produce the largest benefits because regional market power is a significant constraint on auctioning FTRs, and the costs of participating in FTR auctions is likely to be high. Also, significant complications are likely to arise with determining which nodes and regions are competitive and which are not.

1220. Although both initiatives improve the efficiency of spot pricing signals for large consumers, the LRA initiative distorts spot pricing signals for price-taking consumers, and perhaps also for small consumers. The HMDSG believes these efficiency losses are likely to be less than the additional costs associated with FTRs.

1221. The untried nature of the LRA initiative elsewhere in the world and the fact that the full details need to be worked out and developed, suggests that there is greater uncertainty regarding implementation timeframes and cost with the LRA initiative, relative to hybrid FTRs.

8 OVERALL EVALUATION OF THE INITIATIVES

1222. The previous two sections specified each initiative, explained their policy rationale and assessed each initiative against the criteria outlined in section 4.2. This section is structured as follows:

a. Section 8.1 provides a summary of the assessment of each initiative;

b. Section 8.2 discusses the relationships between initiatives;

c. Section 8.3 briefly outlines potential reforms to the physical market that would affect the risk management market, and discusses the implications for the above assessments; and

d. Section 8.4 identifies a preferred package of initiatives and assesses the effect the package is likely to have on achieving the desired characteristics of an efficient market as outlined in section 4.1.

8.1 Summary of individual assessments

1223. The following table summarises the assessments provided in sections 6 and 7. The scores in the table reflect the HMDSG's view regarding each of the initiatives, and are necessarily somewhat subjective.

1224. The first two rows in the table provide a qualitative assessment of the benefits and costs of each initiative, while the third row provides the net benefit assessment. The fourth row indicates the degree of certainty or confidence in the net benefit assessment.

1225. Three ticks indicate the initiative delivers large benefits. Two ticks indicate a moderate benefit and one tick a minor benefit. For costs, we have utilised crosses to indicate large, medium and small in the same ratio.

Figure 36: Summary of individual assessments

CRITERIA	**Evaluation of each initiative against the evaluation criteria**												
	Survey	Publication of contract details	Centralised publication of fuel and outage information	Model master agreement	*EnergyHedge* development	Understanding risk management	Mandatory standardised contracts	Exchange-based trading	Synthetic separation	Mandatory offering requirements	Mandatory purchasing requirements	Hybrid Financial Transmission Rights	Locational rental allocation
Benefits	✓	✓✓✓	✓	✓✓	✓✓	✓	✓	✓	Potentially ✓✓✓	✓	✓	✓✓✓	✓✓✓
Costs	×	×	×	×	×	×	××	××	××	×××	×××	×××	×
Net benefit assessment	✓	✓✓✓	✓	✓✓	✓✓	✓	×	×××	✓✓	××	××	✓✓	✓✓✓
Confidence in net benefit assessment	high	high	high	high	medium	low	low	medium	low	high	high	high	high

8.2 Relationships between initiatives

8.2.1 Mutually excusive initiatives

1226. Initiatives are mutually exclusive if adopting one initiative either precludes the adoption of an alternative initiative, or means that the alternative initiative is no longer required.

1227. In the case of the various initiatives proposed, there are two cases where initiatives are mutually exclusive.

1228. The similarity of LRAs and FTRs means that LRAs would not be required if Hybrid FTR initiative was implemented. The converse, however, is not the case; that is FTRs may be able to be implemented following the implementation of LRAs. For example, the LRA methodology could be applied to FTR auction proceeds, but in this case it is not clear that auctions would achieve a determinative outcome.

1229. If the development commitments for *EnergyHedge* achieve desired results, then the mandatory standardised contracts and exchange based trading will not be required. The desired results are not necessarily substantially increased trading volumes on *EnergyHedge*, but, rather, compelling evidence that underlying demand for standardised derivatives is being met by *EnergyHedge*. If underlying demand is small, then trading volumes can also be small.

8.2.2 Interdependent initiatives

1230. In accordance with the approach adopted by NZIER[29], two initiatives are interdependent if the implementation of one of them materially affects the options available for the other initiative. Interdependencies can be best understood in terms of technical inputs, and particularly whether an initiative requires another initiative to be in place in order to work effectively.

1231. For the initiatives identified, there are two cases where interdependencies exist.

1232. The mandatory standardised contracts initiative has an interdependency with the model master agreements initiative. If the model master agreements initiative is not implemented, then mandatory standardised contracts cannot be achieved because terms and conditions in master agreements could be altered to circumvent the use standardisation of contracts.

1233. The exchange-based trading initiative also has interdependencies, with both the mandatory standardised contracts initiative and the model master agreement initiative. Both are required for exchange-based trading to occur, as exchanges trade standardised derivatives.

[29] See page 19 of “Market Design Report: The Way Forward?” Report to the Electricity Commission, NZIER, August 2005.

8.2.3 Linked initiatives

1234. In accordance with the approach adopted by NZIER[30], two initiatives are linked if the issues around their evaluation or operation are materially connected. Linkages can be best understood in terms of whether their economic outcomes reinforce each other, so that the economic benefits of two (or more) initiatives are greater than the economic benefits of each initiative implemented separately and added together. Another way of considering linkages is whether or not positive interactions exist between two initiatives, or whether there are significant cost savings from implementing both initiatives.

1235. The following table identifies linkages between the preferred initiatives. The shaded cells reflect the fact that linkages are reflexive: if initiative A is linked to initiative B then the reverse applies. Hence, there is no need to score the shaded cells.

[30] See page 19 of "Market Design Report: The Way Forward?" Report to the Electricity Commission, NZIER, August 2005.

Figure 37: Linkages

	Survey	Publication of contract details	Centralised publication of information	Model master agreement	*EnergyHedge* development	Understanding risk management	Mandatory standardised contracts	Exchange-based trading	Synthetic separation	Mandatory offering requirements	Mandatory purchasing	Locational rental allocation	Hybrid Financial Transmission Rights
Survey		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Publication of contract details			✓	✓	✓	✓						✓	
Centralised publication of information						✓							
Model master agreement					✓		✓	✓		✓	✓		
EnergyHedge development										✓	✓	✓	✓
Understanding risk management										✓	✓	✓	✓
Mandatory standardised contracts								✓		✓	✓	✓	✓
Exchange-based trading										✓	✓	✓	✓
Synthetic separation													
Mandatory offering											✓		
Mandatory hedging													
Locational rental allocation													✓
Hybrid financial transmission rights													

1236. The regular survey initiative is linked with all of the preferred initiatives because the survey will report on the success of any initiatives that are implemented. The regular survey is directly linked with the understanding risk management initiative, as the survey will inform prospective participants of how the market is performing, and therefore improve their understanding of broader risk management issues.

1237. Publication of contract details and the centralised publication of fuel and outage information are linked with the regular survey, understanding risk management and development of *EnergyHedge* as all of these initiatives contribute to providing more information and increasing the understanding and knowledge of participants. Publication of contract details is also linked to model master agreements, hybrid FTRs and locational rental allocation as these all assist with evolving the market towards more standardised contracts.

1238. Model master agreements are linked with the development of *EnergyHedge*, mandatory standardised contracts and exchange-based trading, and the mandatory offering and mandatory purchasing initiatives. Model master agreements will reduce contracting costs and help facilitate trading between participants through each of these mechanisms.

1239. The development of *EnergyHedge* is linked with the mandatory offering and mandatory purchasing initiatives as *EnergyHedge* could be developed into an appropriate platform for participants to use to comply with the mandatory offering and purchasing requirements. In addition, the development of *EnergyHedge* is linked with both LRAs and hybrid FTRs, as the development of *EnergyHedge* will be more effective if greater standardisation is facilitated through addressing locational price risk. As mentioned above, the development of *EnergyHedge* is also linked with the model master agreement initiative.

1240. As mentioned above, understanding risk management is linked with the publication of contract details, the centralised publication of information, the regular survey, and the development of *EnergyHedge*, as understanding risk management will help participants interpret the information provided via these mechanisms. Understanding risk management is also linked with the mandatory6 offering and the mandatory purchasing initiatives as understanding risk management will help participants understand the ramification of the two initiatives and make better decisions in regard to their obligations. Understanding risk management is also linked with LRAs and the Hybrid FTR initiative, as both of these will significantly affect the risk management strategies of participants.

1241. Mandatory standardised contracts is linked with exchange-based trading, as exchange based trading will require standardised contracts in order to be able to work effectively. Mandatory standardised contracts are also linked with mandatory offering and mandatory hedging, as the effectiveness of these initiatives will be increased through having standardised contracts. In addition, mandatory standardised contracts is linked with both LRAs and hybrid FTRs, as having LRAs and hybrid FTRs in place will reduce the need for location-based contracts.

1242. Exchange based trading is linked with the mandatory offering and mandatory purchasing initiatives as an exchange could be used as the platform for participants to use to comply with the mandatory offering and hedging requirements. In addition, exchange based trading is linked with both LRAs and FTRs, as an exchange will be more effective if greater standardisation is facilitated through addressing locational price risk. As mentioned above, exchange based trading is also linked with the model master agreement initiative.

1243. Mandatory offering and mandatory hedging are also linked. This is because the mandatory hedging initiative requires purchasers to be hedged, but does not guarantee hedges will be offered. Consequently, the mandatory hedging initiative is improved if mandatory offering is also in place.

1244. LRAs and hybrid FTRs are linked, in that hybrid FTRs could be implemented following the implementation of LRAs, thus improving the ability of parties to manage locational price risk.

8.3 Qualifications to the above assessments

1245. The assessment in sections 8.1 and 8.2 omitted consideration of possible reforms to the underlying physical market that may affect risk management outcomes. This section outlines key reform possibilities, and discusses their implications for the above assessments.

8.3.1 Potential underlying market initiatives

1246. The HMDSG identified three underlying market initiatives that could potentially benefit electricity risk management. These were:

- zonal pricing;
- a day-ahead market; and
- a generation capability market.

1247. The following discussion briefly explains what each initiative is, and explains why it is relevant to risk management. The discussion does not attempt to fully describe each initiative and nor does it discuss their advantages and disadvantages beyond the risk management market.

Zonal pricing

1248. Zonal pricing is a market pricing system that groups nodes into zones, and charges spot market participants zonal prices rather than nodal prices. In some jurisdictions, such as Singapore, generators receive nodal prices but consumers pay zonal prices.

1249. In regard to the risk management market, zonal pricing could facilitate greater liquidity in the derivatives market by focusing derivative contracting around a small number of reference prices. Zonal pricing is used in a number of jurisdictions, most notably the Australian NEM and Nordpool. Both of these markets have a high degree of liquidity, and although their liquidity levels can be attributed to many other factors, zonal pricing may have contributed to those outcomes.

1250. Having said that, in New Zealand most derivatives are referenced to one of a few main generation hubs anyway, which in all probability would form some of the main zones under a zonal pricing market. Probably the main risk management advantage of zonal pricing is that it would reduce locational price risk within each zone, but these effects would be minimal if zones are defined over collections of nodes with similar prices.

1251. Another advantage of zonal pricing is in terms of the reconciliation process. If zonal pricing was introduced, the reconciliation process would become significantly less complex and result in significant cost savings.

A day-ahead market

1252. A day-ahead market is a market in which participants make bids and offers and have contracts dispatched at prices determined one day in advance of real time. Day-ahead markets operate in the Nordpool and PJM markets, and also in the market covering England, Wales and Scotland (called the BETTA market).

1253. Day-ahead markets can be physical or financial. A physical day-ahead market would require changing the spot market to a balancing market, where parties bid increments and decrements on their day-ahead volumes. In contrast, a financial day-ahead market issues CfDs and the spot market remains a gross market as now – the only adjustments required in this case would be in the settlement of spot market trades.

1254. Under a day-ahead market, only uncontracted quantities are exposed to spot prices. As day-ahead prices exhibit much lower volatility than real-time prices, this would reduce parties’ half-hourly risk exposures but it wouldn’t alter exposures extending beyond a day.

1255. A day-ahead market could be designed to determine a single day-ahead price, rather than day-ahead nodal prices. The single day-ahead price could provide a natural reference point for longer maturity derivative contracts, which could enhance derivative market liquidity. It could also largely remove loss and constraint rentals from the spot market, and substantially reduce locational price risks, as nodal price differences would apply only for volume differences between the day-ahead and spot markets.

Generation capability market

1256. A capability market is a market where generators would be paid to ensure they have sufficient generation capability to meet forecast demand. The Commission would set aggregate obligations sufficient to meet its forecast of aggregate annual demand, possibly split into smaller time periods such as months or quarters. This would entail the Commission setting up a market and developing rules for the operation of the market. Generators would be able to trade 'capability tickets' in a secondary market to avoid penalties for breaching their generation capability obligations as set through the market.

1257. In regard to risk management issues, the main effect of a generation capability market is that it could be used to achieve larger margins between generation capability and annual demand than occurs under the market structure currently in place in New Zealand. Larger margins could create more generation resources offering derivative contracts, and perhaps achieve more competitive spot market outcomes (if that was of concern). Smaller swings in the margin, if they occurred, could reduce volatility in the availability of derivative contracts.

8.3.2 Implications for the above assessments

1258. Section 8.3.1 briefly described how various physical market initiatives may affect risk management market outcomes. This section considers whether introducing any of these initiatives would alter the net benefit assessments of the risk management initiatives presented in sections 6 and 7.

Zonal pricing

1259. Introducing a zonal pricing market would not greatly affect any of the net benefits assessments in this paper. There would still be considerable value in conducting an annual risk management market survey, publishing key contract details, reconfiguring the publication of fuel and outage information, encouraging the adoption of a model master agreement, further developing *EnergyHedge*, and so on. While offering some risk management benefits, zonal pricing leaves parties facing much the same energy price risks as under the nodal pricing system. Zonal pricing would reduce the locational risks faced by some customers, particularly if the number of zones was relatively low, but this would involve wealth transfers within the zones. The LRA proposal could be considered a move towards a zonal pricing approach.

A day-ahead market

1260. The day-ahead initiative appears to have some value for risk management. In this case it appears a day-ahead market could enhance derivative market liquidity and enhance the net economic benefits for the generic initiatives already showing net positive benefits.

1261. Importantly, a day-ahead market could address locational risk issues, even more so than LRAs or FTRs, which only cover imported power flows. As a result, introducing a day-ahead market could alter the net benefit assessments of these initiatives, such that it would be prudent to consider a day-ahead market in tandem with the consideration of the LRA and hybrid FTR initiatives, as it could obviate the need for either mechanism.

Generation capability market

1262. A generation capability market would only be relevant to risk management issues if the problem is that the overall level of derivatives available is too low as a result of a shortage of generation capability relative to demand. It would do little for achieving a more efficient mix of risk management instruments or for growing underlying liquidity in the derivatives market.

1263. A generation capability market appears to force a solution on the risk management market rather than build confidence in the market. There would still be a need for a regular survey, for publication of contract details, for a model master agreement, and so on. There would still need to be an effective mechanism for dealing with locational price risks.

1264. The primary initiatives affected by a generation capability market would be the mandatory offering and purchasing initiatives in sections 6.11 and 6.12, but neither of them appears to provide positive net benefits.

Conclusions

1265. While the above measures are often touted as providing significant benefits for risk management, the generic risk management initiatives considered in section 6 are foundational measures that stand on their own merits. The day-ahead initiative appears to be the only physical initiative with any real potential value for risk management, and should be considered in tandem with the consideration of the LRA and hybrid FTR initiatives.

8.4 Preferred package of initiatives

8.4.1 Preferred package

1266. The assessment in section 8.1 compares the individual assessments of the different initiatives. Section 8.2 discusses the relationship between the initiatives. Based on the assessment in these two sections, the HMDSG considers that the following package of initiatives provides a balanced approach to achieving the objective of facilitating more efficient electricity risk management:

a. Regular survey;

b. Publication of contract details;

c. Centralised publication of information;

d. Model master agreements;

e. *EnergyHedge* development;

f. Understanding risk management; and

g. Locational rental allocation.

1267. The primary basis for selecting these initiatives is the evaluation summarised in section 8.1. All seven initiatives selected for the preferred package have a positive net benefit.

1268. The linkages between initiatives show that the package of initiatives is mutually reinforcing. That is, these initiatives support one another in contributing to achieving the objective of facilitating more efficient risk management.

1269. There are strong linkages between the regular survey, publication of contract details, centralised publication of fuel and outage information and understanding risk management. There are also strong linkages between publication of contract details, model master agreements, *EnergyHedge* development and LRAs.

1270. In addition, all the initiatives included in the package are relatively non-intrusive. This means, that while they do contain an element of regulatory intervention, they are focussed primarily on facilitating an environment for efficient risk management and allowing for evolution by market participants in ways that best meet the needs of participants. For example, if the commercial drivers exist, exchange trading could be introduced at any time.

1271. If this evolution does not occur the Commission has the option of introducing more intrusive initiatives at a later stage.

8.4.2 Does the package provide the characteristics outlined in section 4.1?

1272. As discussed in section 3.3, the overall objective of the work stream is to develop an efficient risk management market. Six characteristics of an efficient risk management market were identified in section 4.1, being:

a. efficient and timely disclosure to the market of essential information relating to the sale or purchase of risk management instruments;

b. efficient availability of risk management instruments at efficient market prices;

c. efficient costs of trading risk management instruments, within well-designed market rules;

d. an efficient degree of comparability of prices and other key terms;

e. an efficient level of understanding of electricity pricing risks and how to manage those risks; and

f. an efficient level of market-making and broker activity. The package of initiatives contributes to developing these characteristics in a number of ways. The contribution to each characteristic is discussed below.

Efficient and timely disclosure to the market of essential information relating to the sale or purchase of risk management instruments

1273. Three initiatives contribute directly to this characteristic, being:

- publication of contract details;
- centralised publication of fuel and outage information; and
- the regular survey.

1274. The development of *EnergyHedge* would indirectly contribute to this characteristic, as it would provide a more robust forward price curve available to everyone on an equal basis.

1275. Understanding risk management would also indirectly contribute to achieving this characteristic, as participants would be able to interpret and use information better, which would in turn facilitate increased provision of information.

Efficient levels of availability of risk management instruments at efficient market prices

1276. The initiative that contributes directly to this characteristic is the development of *EnergyHedge*, as this would provide a continuous and ready platform for standardised derivatives to be offered to the market. The development of *EnergyHedge* would also provide an appropriate mechanism for determining efficient market prices.

1277. The LRA initiative enables participants to trade these standardised derivatives, or any other energy CfD, by providing an efficient tool for managing locational risk.

1278. Initiatives that facilitate greater levels and use of information for participants would indirectly lead to more efficient pricing. The initiatives that would indirectly contribute to this characteristic include:

- publication of contract details;
- centralised publication of fuel and outage information;
- the regular survey; and
- understanding risk management.

Efficient costs of trading risk management instruments, within well-designed market rules

1279. Several initiatives contribute directly to this characteristic.

1280. Model master agreements would greatly reduce the transaction costs for participants, as participants could use the model master agreements rather than going through the costly exercise of negotiating ISDA master agreements.

1281. LRAs would increase the standardisation of contracts, therefore making it easier and less costly for participants to trade.

1282. Further development of *EnergyHedge* would also be a relatively inexpensive mechanism for trading, and could make it easier and cheaper for participants to trade.

An efficient degree of comparability of prices and other key terms

1283. The initiative to further develop *EnergyHedge* contributes strongly to this characteristic because it would allow parities to establish more robust forward price curves.

1284. Publication of contract details would also assist comparability, as parties will be able to clearly see the prices and terms struck in historic contracts.

1285. Model master agreements would remove unnecessary differences in contract terms, allowing parties to readily compare offers from different parties.

1286. LRAs would also encourage greater standardisation of contracts by reducing counterparty exposure to location risk, thus facilitating greater use of standardised derivatives, which are consequently easy to compare.

An efficient level of understanding of electricity pricing risks and how to manage those risks

1287. The primary initiative contributing to this characteristic is *understanding risk management*.

1288. Other initiatives provide greater levels of information to participants, which would indirectly encourage participants to develop or acquire greater levels of risk management skills in order to better utilise the information. These initiatives include:

- publication of contract details;
- centralised publication of fuel and outage information;
- the regular survey; and
- model master agreements.

An efficient level of market-making and broker activity, introducing participants to opportunities and risks

1289. Further development of *EnergyHedge* could contribute to this characteristic as it could provide a platform for brokers to secure contracts on behalf of consumers.

1290. Model master agreements and LRAs would also contribute to this characteristic as they facilitate greater use of standardised derivatives.

9 SPECIFIC DISCUSSION QUESTIONS

1291. As noted in the foreword to the discussion papers, the Overview Paper and Section 1.4 of this paper, the Commission would like responses to specific discussion questions. These questions are outlined below. Note that these discussion questions are the same as those contained within the foreword and the Overview 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 3.3? If not, please outline what you consider to be the problems;
3. Do you agree that the evaluation criteria outlined in Section 4.2 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 this 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 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: Hedge market survey

1292. The Commission engaged UMR Research to conduct a study to provide information that would assist in determining:

- whether or not there is a shortage of hedge contracts in the market;
- what constitutes an effective contract from a buyer's perspective, particularly the relationship between price, basis risk and force majeure;
- whether generators have the ability to exercise market power in either the wholesale spot market or the wholesale hedge market and, if so, the extent of that power and its implications for the hedge market;
- whether vertical integration adversely affects competition in the retail market, the market for hedges and investment in new generation;
- whether vertical integration is the most efficient market structure given the physical and commercial drivers underlying the New Zealand electricity market; and
- whether issues relating to the lodgement of hedges for prudential security are significant.

1293. It should be noted that the research was not designed to provide answers to those questions, but to gather information to assist the Commission's determinations.

1294. Those surveyed included generators, retailers, large users (>1000GWh/annum), medium users (between 500GWh and 1000GWh/annum), small users (between 200GWh and 500GWh/annum), energy agents and distributors.

1295. The survey methodology comprised of two information gathering phases. The first phase involved the distribution of a survey that was developed by the Commission (with input from UMR and the HMDSG) to 69 potential respondents. Of those surveyed, 51 responses were received.

1296. The second phase of the research involved 35 depth interviews, which were designed to better understand the reasons behind the responses given to some key questions in the survey. Requests for interviews were made to all generators and generator/retailers, all large purchasers and a selection of medium and small purchasers, and a selection from the mixed category of distributors, traders and potential and past retailers.

1297. All parties were assured that the survey was conducted on a confidential basis, although three parties, Delta, Orion and NGC subsequently granted permission for UMR to identify them in the survey report.

1298. The complete report on the results of the survey is available on the Commission website at: www.electricitycommission.govt.nz/opdev/wholesale/hedgesurvey.

10.2 Appendix B: Potential generic risk management initiatives

1299. To identify possible initiatives for improving the risk management market, the HMDSG listed all possible initiatives it could think of, regardless of their likely merits. It then selected for detailed analysis I sections 6 and 7 initiatives that it thought warranted further consideration, either because they showed promise for because the initiative was often a topic of discussion among market participants or because the initiative was in the GPS.

1300. This appendix outlines the other generic risk management initiatives discussed by the HMDSG, sometimes very briefly. The list of initiatives below details the options that were considered, but it should not be inferred that the Group believe any or all of the initiatives were credible options. It is important to stress that the discussions contained in this appendix represent the HMDSG's preliminary views as at July 2005.

1301. In the early phase of its work the HMDSG identified several issues that may need to be addressed. The issues relating to generic risk management are:

a. information disclosure;
b. vertical integration;
c. standardised contracts;
d. credit risk;
e. trading mechanisms;
f. encouraging market makers;
g. mandatory market participation;
h. energy risk awareness; and
i. addressing location price risk

1302. Other locational price risk initiatives are covered in Appendix C and other initiatives related to the nature of the underlying physical market are outlined in Appendix D.

10.2.1 Information disclosure initiatives

Use of insider trading rules

1303. In addition to the requirement to publish contract details in section 6.3, this option would require vertically integrated participants to publicly disclose any information that may affect the price of hedges in advance of completing an internal or external trade.

1304. This is very similar to the requirements on companies listed on the stock market to continuously disclose information that might affect the share price.

Centralised forward price curve derivation

1305. Currently M-co publishes a fixed price contract index; derived from prices for contracts of various durations, start dates, volumes, locations, credit risks, and force majeure clauses. The wide variation in the types of contracts included in the index makes it difficult to ascertain a meaningful price indicator for individual transactions.

1306. Replacing that mechanism, in conjunction with disclosure of contract details, a centralised system could be developed for generating independent forward price curves , based on an agreed set of input factors. An agreement would first be required on those factors and how they would be used in published contract details.

Publication of contracted positions

1307. This initiative requires participants to disclose their contract positions. If parties were required to publicise their overall net position, other participants would be able to gauge the extent to which the parties might be withholding volume from the hedge contracts market, and thereby potentially exercise market power.

10.2.2 Initiatives relating to vertical integration

Ownership separation

1308. The most severe way of reducing vertical integration is requiring vertically integrated companies to divest ownership of either the generation or retail parts of their business. Implementing this option would require primary legislation, similar to the Electricity Industry Reform Act 1998.

Vertical integration capping

1309. As opposed to totally divesting one or other part of the business, vertically integrated generator/retailers could be required to "sell-down" their retail (or generation) businesses to a certain percentage of their generation (or retail) business, and maintain their ongoing generation/retail balance below a regulated level.

Operational and accounting separation

1310. Instead of requiring ownership separation or capping the degree of vertical integration, there could be a requirement for operational and accounting separation of each part of the business. Under this approach, each part of the business would operate independently of the other, with its own senior management team and reporting in separate accounts. Both businesses would remain owned by the same interests.

10.2.3 Initiatives for standardised contracts

Standard contract types

1311. In the Australian National Electricity Market (NEM), six main contract types are traded. These are:

a. baseload swaps;

b. peak swaps (7am-10pm business days);

c. off-peak swaps (all times not covered by peak swaps);

d. baseload caps (half-hourly based, automatic exercise);

e. baseload swaptions (options to purchase a swap); and

f. baseload captions (options to purchase a cap).

1312. A comparable set of model or mandatory types could be established in New Zealand. An option would be to start with a core set of three types, and allow others to develop as required over time. A suggested initial set of products is:

a. baseload swaps;

b. peak swaps (7am-10pm business days); and

c. baseload caps.

Standard contract durations

1313. A set of standard contract durations would go hand-in-hand with standard contract terms. *EnergyHedge* currently facilitates trades in quarterly contracts up to two years out, and monthly contracts inside the current quarter. The shortest duration for a standard contract is normally weekly.

1314. For New Zealand, initially a minimum duration of one month is suggested as appropriate within the current quarter (i.e. the same as *EnergyHedge*). Up to two years out, quarterly contracts are probably the optimal duration, and further than two years out, durations are easier to trade in annual blocks.

Standard contract locations

1315. Having contracts priced at a large number of different nodes inhibits market liquidity. Standardising the buy/sell point of contracts to a small number of locations could to improve liquidity, provided that parties are capable of managing any locational risk that is introduced in the process.

1316. Several options have been put forward for an initiative to standardise location. One is to use a single locational reference point (the Haywards node, which is currently used by *EnergyHedge*), and the other is to have contracts offered at three price reference points (Benmore, Haywards and Otahuhu[31]).

1317. The locational risk faced by buyers and sellers will be included in contract pricing or covered by a separate locational (transmission) hedge contract.

Requiring parties to use CfDs

1318. Most retail electricity contracts are fixed price variable volume (FPVV) contracts, which are not amenable to market trading. Many large electricity users prefer to use FPVV contracts to manage electricity price risk, although a CfD may be more appropriate.

1319. One way of addressing this issue is to require all parties above a certain electricity usage (say 10GWh/annum, which is equivalent to just over 1MW baseload) to make the majority of their purchases using a CfD rather than a FPVV contract.

10.2.4 Initiatives for reducing credit risk

Mandatory credit ratings

1320. One way of addressing the credit risk issue would be to require all hedge market participants to hold an internationally recognised credit rating score above a certain level.

1321. A variant of this would be to have a third party monitor the net wholesale position of each participant and rate participants' creditworthiness in terms of hedge market arrangements. The rating would be visible to all potential counterparties.

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[31] For the upper North Island, there are three main generation nodes: Whakamaru, Huntly and Otahuhu. In this case, Otahuhu is the preferred node as it is located in closest proximity to the main load centre.

Mandatory price premiums based on credit rating

1322. In the hedge market, credit risk is normally priced into the contracts. Currently, sellers of hedges often use subjective judgment to price contracts at higher levels to reflect their perception of the creditworthiness of counterparties. One option to address credit risk concerns is to introduce a standard method of calculating creditworthiness premiums for hedge contracts.

1323. This initiative would require establishing an accepted method for calculating premiums based on an agreed credit ratings methodology, and mandating its use. The credit rating or premium applied would also need to be included in contract details[32] disclosures, so that forward price curves could be derived.

Use of prudential security

1324. Currently wholesale spot market purchasers are required to provide the Clearing Manager with prudential security for the equivalent of 57 days electricity purchases. Hedge contracts can be lodged as prudential security, but for a number of reasons, only a small number of hedges have been lodged with the Clearing Manager[33].

1325. An alternative to the above and the credit rating suggestions would be to require contract counterparties provide prudential security for their net exposure positions in the spot and contracts markets. The Clearing Manager would be the central point for prudential security management and make net payments to participants based on the physical and contractual positions when clearing and settling the markets.

1326. For longer-duration contracts, there will be a need to do mark-to-market assessments in order to manage the levels of prudential security required by participants with contracts. Provided that all contract information is provided to the Clearing Manager, and that a reasonable forward price curve can be derived, the prudential security requirements calculations would be relatively straightforward.

Restricted participation

1327. Rather than requiring all participants in the contracts market to place prudential security with the Clearing Manager, credit risks could be reduced by restricting contracts market participation to those qualified to operate in the wholesale electricity market. The prudential requirements would be linked as described above.

1328. This approach would enable secondary market contract trading with parties that are not wholesale spot market participants, by requiring any primary contracting party that on-sell to such a secondary party to cover secondary party default risk.

10.2.5 Trading mechanism initiatives

Brokers

1329. In the Australian wholesale electricity market, brokers are the primary mechanism for facilitating hedge contract trading[34] – and virtually all such trading is blind. In New

[32] Unless some other mechanism was employed to address the credit risk issue, contract details disclosures should include any explicit or implicit credit risk premium included in struck contracts.
[33] Currently hedges are only lodged as spot market prudential security when both parties to the hedge agree, but there might be efficiencies in requiring all hedges to be lodged as prudential security.
[34] There are around seven main brokers in Australia who have their own websites that display contract prices for each type of standard contract and the different contract durations.

Zealand there are a small number of brokers who operate on behalf of large users to negotiate hedge contracts from the generators, but these brokers do not operate on behalf of the generator/retailers.

1330. Brokers come into play where there are opportunities to bring willing buyers and sellers together, and there is a margin for doing so. In an environment where those opportunities appear to be limited, there might be a case for providing some form of encouragement to the entry of one or a number of brokers to prime the market into action. Alternatively, the use of brokers for all non-related party contracts could be mandated.

Central trading platform

1331. *EnergyHedge*, the central trading platform used by the five main generator/retailers to trade among themselves, provides a model for this initiative. With *EnergyHedge*, participants post both buy and sell prices for standard contracts, and once contracts are struck, the parties enter into bilateral contracts in accordance with the terms agreed.

1332. A central trading platform specified by the Commission could bean enhanced version of *EnergyHedge;* a specified securities exchange or a specified brokering service. A platform based on the *EnergyHedge* model might be implemented by:

- requiring the owners of *EnergyHedge* enable it to meet specified functionality and participation capabilities; or
- creation of a new central trading platform to supplant *EnergyHedge* - effected through direct ownership by the Commission or by the providing an independent agent with exclusive rights (conferred under industry rules).

1333. Whatever owner/operator model was adopted, functionally the platform would provide:

- the opportunity for a wide range of potential counterparties to participate;
- visibility of buy and sell prices, and all other relevant information in relation to potential and struck contracts;
- controls over maximum spread of bid and offer prices where two way prices are posted on the platform;
- trading of a suite of standard contracts;
- blind trading until contracts are struck (& then bilateral contracts); and
- the opportunity for single-sided bids or offers.

10.2.6 Initiatives to encourage market makers

Participant & fee differentiation

1334. The potential benefit from this initiative is that, with the establishment of a trading platform or exchange, participants that make a particular contribution to market depth and liquidity (more than their basis risk cover need would indicate) should be rewarded for their effort through providing them with preferential fees. Availing such participants to a preferential fee structure has the potential to encourage higher levels of market participation.

1335. For this initiative to get off the ground, there needs to be an electricity industry specific energy contracts trading platform that the industry can exercise its prerogative to establish a differentiated fee structure in. Consequently, the initiative would be in conjunction with the industry development of *EnergyHedge* or some other central trading platform specific to the electricity contracts market.

1336. The market or exchange operator may offer an incentive to market making participants by way of lower market and/or transaction fees. In Australia, brokerage fees are negotiated between the brokers and traders, and market maker traders have significantly lower fees than other market participants.

1337. The initiative might involve identifying a number of different participant classes for the market – with each class having a particular set of participation requirements and attracting a different level of market and/or transaction fees. For instance:

- a trader class participant would be required to post both bid and ask prices (with a maximum spread) and attract a minimal transaction fee;
- a purchaser/generator[35] class participant would only have to post a single bid or offer price (as applicable) and would have higher transaction costs; and
- an intermittent[10] class participant would be able to post prices only when it wanted and would have significantly higher transaction costs.

1338. An alternative to the above differentiated fee structure would be to require the purchaser/generator class to post both bid and ask prices and attract a particular level of market fee, and allow other participants to post single prices but be subject to a higher market fee.

1339. Another incentive approach would be to develop a code of practice for hedge market participants, with a fees reduction incentive given to participants who sign up to the code and behave accordingly. A behavioural measure might consider the effective contribution that a participant makes to market liquidity, and reward through preferential market and/or transaction fees.

Designated external market maker

1340. Contracting one or more external parties (such as a bank) to participate as designated market makers would be a further way of facilitating market development. Encouraging designated market makers would likely require substantial incentives, including lower fees and possibly a risk premium paid to the market makers by the market operator.

10.2.7 Mandatory market participation initiatives

Mandatory tendering of contracts

1341. This potential initiative envisages mandatory tendering of (a minimum percentage of some measure of capability) hedge contract offerings by generators through a tender process administered by an independent third party. Contracts would be allocated to bidders based on bid price, working down the demand curve until either all of the demand is satisfied or the remaining bids are below a regulator-defined reserve price.

1342. The strike price for all contracts would be the tender clearing price (the lowest price above the reserve that satisfied all demand). Bilateral contracts would then be struck

[35] 'Purchaser/Generator' and 'Intermittent' Classes would also have to comply with the maximum spread requirements if they posted both bid and offer prices.

between successful bidders and generators. The tender clearing contract price would be disclosed after the auction.

1343. There might need to be more than one reserve price, depending on the operating costs of the generation plants offered. The reserve price(s) would be published in advance of the tender round.

1344. The tender manager or the regulator would define the quantity of hedge to be offered in each auction and monitor the volume of hedges contracted. A number of factors influence generation capability, and information asymmetries will hinder independent monitoring.

Mandatory minimum contracting

1345. Similar to mandatory tendering of contracts, this initiative would require generators to sell minimum volumes of their generation capability (energy) as standard products in the hedge contracts market.

1346. The minimum volume requirement would be based on dry year or mean inflow generation capability, or predicted generation levels (using independent forecasts) - recognising also participants' needs for tailored contracts that would not be readily tradable in the contracts market. That is, in setting the minimum contracted level, there would need to be quantification of nominated generation capability and the degree to which the generator/retailer needs to have non-tradable contracts before its quantity of generation to be put into standard hedge contract products was set.

1347. The initiative would be very intrusive, substantially negating the value of vertical integration as a risk management strategy. A linkage to dry-year capability would cap the increased risk exposure of vertically integrated participants. The change would be significant for vertically integrated parties, but provided the minimum is set low enough to minimize the new risk, contracts should be priced at efficient normal year costs - constrained by the threat of new entry.

10.2.8 Energy risk awareness

Promotion of a network of advisors

1348. There are a number of independent risk management advisors operating in New Zealand, who could be encouraged to include energy purchasing risk management in their portfolio of services. Those that take the opportunity could be supported through various forums and industry communications.

Trader certification

1349. Incompetent traders have the potential to undermine confidence in the integrity of the market, by attributing their behavioural failures to the nature of the market or the market power of the main participants. A way of ensuring that such traders are competent is to require that that they be certified in order to be able to trade. Certification might require satisfactory completion of appropriate electricity risk management and general electricity industry courses.

Provide standard risk management tool

1350. One reason for reluctance to participate in the contracts market might be a lack of a suitable electricity risk management tool for use by purchasers. The tools available tend to be complex and expensive, and are generally only used by the larger organisations.

1351. An option would be for the Commission to purchase (or build) a simple risk management tool that can then be provided (perhaps at a subsidised cost) to larger energy users and traders to improve market participation by these parties.

1352. Alternatively, as a condition of participating in the market, retailer participants might be required to make such tools available to their customers. Several retailers already provide similar services – partly free and partly subject to user fees.

10.3 Appendix C: Other transmission risk management initiatives

1353. As discussed in Appendix B, to identify possible initiatives for improving the risk management market, the HMDSG listed all possible initiatives it could think of, regardless of their likely merits. This appendix outlines transmission risk management initiatives briefly discussed by the HMDSG and not included in section 7. The list of initiatives below is provided in the spirit of openness and it should not be inferred that the Group believe any or all of the initiatives were credible options. It is important to stress that the discussions contained in this appendix represent the HMDSG's preliminary views as at July 2005.

1354. The other initiatives identified by the HMDSG were:

- pure financial transmission rights regime;
- rental revenue share auction; and
- location contracts-for-differences.

10.3.1 A pure financial transmission rights regime

1355. FTRs are a mechanism by which parties can obtain a fixed MW right to some of the loss and constraint rentals for the trading period and the (directional) transmission circuits covered by the FTR.

1356. The appendix to the GPS outlines a specific design for FTRs, which is based primarily on the Read Report.

1357. The FTR option would involve use on a specific optimisation engine to assign rentals to grid circuits. The option would also include methodologies for:

a. initial assignment of FTRs to transmission customers;

b. identifying the FTRs suitable for auctioning and part of any secondary market;

c. allocation of loss and constraint rentals relating to the FTRs not part of the auction or FTR market; and

d. allocating auction revenues and residual rentals.

10.3.2 Rental revenue share auction

1358. This option involves auctioning shares in HVAC rentals. Participants would bid for percentages of the total revenues over a specified timeframe. The participants who won the auctions would pay the auction clearing price, and receive the proportion of rentals that their auction bid applied to. This is similar to the Settlement Residue Auction (SRA) used in Australia to distribute inter-connector rental revenues from the NEM.

1359. The revenue obtained from the auction of the rental revenue shares would be paid to transmission customers as a replacement for the current direct payment of the rentals. Transpower would not have any increased risk exposure.

10.3.3 Location contracts for differences

1360. This option would involve Transpower calculating location factors between market nodes (based on its assessment and knowledge of the transmission system) and making transmission risk management contracts available to participants based on the calculated location factors.

1361. This option would see Transpower, as grid owner and system operator, assuming some additional risk in relation to its management of the transmission system. All HVAC rentals would be used to fund the contracts issued, and Transpower would either retain the difference if rentals are greater than the payments to participants, or fund the difference if payments are greater than the rentals.

1362. As counterparty to the contracts, Transpower would have a strong incentive to manage the network as efficiently as possible in order to reduce the level of constraints in the grid.

10.4 Appendix D: Other underlying physical market options

1363. As discussed in Appendices B and C, to identify possible initiatives for improving the risk management market, the HMDSG listed all possible initiatives it could think of regardless of their likely merits. This appendix outlines possible physical market initiatives that could assist with risk management but these issues go beyond electricity risk management and beyond the mandate of the HMDSG.

1364. The list of initiatives below is provided in the spirit of openness and it should not be inferred that the Group believe any or all of the initiatives were credible options. It is important to stress that the discussions contained in this appendix represent the HMDSG's preliminary views as at July 2005.

10.4.1 Encouraging surplus generation capability

1365. In these options, demand-side contributions can be facilitated through a central mechanism. Such a mechanism can be in the form of a market, which is commonly known as a demand exchange. Demand exchanges are not specifically discussed in this paper, although they may form part of a specific proposal. One of the major difficulties with demand exchange trades is that it is difficult to accurately measure load reduction relative to the counterfactual (i.e. the situation if the demand contract had not been called on).

Capability market

1366. Demand would be forecast by the Commission, and generators would offer in generation capability (measured in GWh) for specified periods of time, say on a monthly or quarterly basis. The offers would be cleared up to the amount of generation required to meet forecast demand, and all generators that have their offers cleared would be paid the price of the highest priced offer that cleared.

1367. The cost of payments made to the generators would be recovered either through the levy of market participants, allocating costs to specific participants (such as purchasers and/or distributors) or by adding the cost to each half-hourly spot price.

1368. Generators that were not able to meet their commitments would be able to contract out of their requirements by paying another generator to take on the commitments. This would most likely result in a secondary market for capability. The price in the secondary market would reflect generators' perceptions about whether they would be able to meet their obligations. If parties were not able to meet their obligations, and the obligation was met by another generator, the defaulting generator would be required to pay the current secondary market clearing price for the energy.

Capability obligation

1369. Under this option the Commission would require all generators to generate a certain level of generation over specified periods. In the New Zealand context (with high hydro-dependence) this would involve requiring each generator to have sufficient generation capability in its portfolio (including contracts with other generators and demand-response) to cover forecast demand. This option is similar to the capability market option, but would require generators to generate to defined levels rather than paying them to do so.

1370. The Commission would forecast demand and specify the minimum generation capability for each generator. That minimum could be calculated, for example, as the expected level of generation under a mean-inflow scenario or average historical generation. At any point in time a generator would be required to hold sufficient capability to meet its allocated minimum requirement.

1371. Generators would be obliged to generate to their allocated requirement level or, if they are unable to generate to that level, contract a third party to generate or reduce demand in order for them to meet that requirement. A market would be likely to develop for parties to be able to easily contract with third parties to meet generation requirements.

Capability contracting

1372. An alternative to a capability market or a capability obligation is to require purchasers to contract directly with generators to guarantee energy capability.

1373. Purchasers would be required to always hold sufficient capability tickets to cover their month-ahead obligation and trade as necessary to maintain that position, in the face of changes to forecast demand positions due to growth and retail competition. The tickets would be expressed in GWh of capability.

1374. Purchasers would be required to hold, at the beginning of each month, hedges in the form of forward contracts, call options or demand response capability totalling at least some predetermined percentage (say 90 percent) of their next month's forecasted load.

1375. Facilitating a market for long-term capability hedging obligations would enable reserve generation capacity to secure a stable income stream in return for a commitment to sell energy at reasonable prices when needed.

10.4.2 Pool arrangements

1376. The New Zealand spot market uses a gross pool approach. This means that all generation and load is offered and bid into the market on a gross basis. That is, all participants (apart from a small number of small and/or embedded generators) have to offer or bid for all generation and load. The alternative net pool approach allows participants to net off generation and load, which means they only have to bid or offer in their net load or generation, which gives them more flexibility in terms of the operation.

1377. The spot market is also an ex-post market, in which prices are calculated after the event. The alternative ex-ante market has prices calculated in advance, which gives participants greater confidence in the market price.

1378. In contrast to the New Zealand model, some other jurisdictions (most notably BETTA, the UK model) use a net pool in which some prices are calculated ex-ante, that is, in advance of the event, but after bids and offers have been made.

1379. In a net pool, participants bid and offer into the market on a net basis. That is, there is some self-dispatch and participants offer and bid to the pool only the quantities that they wish or need to expose to the spot price.

1380. In some market environments, the net pool model has been credited with encouraging longer-term energy contracts (eg power purchase agreements) and more customisable deals. However, it is difficult to ascertain whether the net pool model would do the same in New Zealand. Having said that, NZEM was a net pool model and the introduction of the current gross pool does not appear to have changed contracting behaviour significantly.

10.5 Appendix E: Specification of a potential mandatory offering regime

10.5.1 Introduction

1381. The Act provides for the Commission to recommend to the Minister that generators be required to tender a minimum volume of hedges. As with any other regulatory proposals, the GPS directs the Commission to recommend regulations only if it has first established that there are significant problems that are not resolvable through voluntary arrangements and co-operation.

1382. This appendix specifies the options and mechanisms for implementing mandatory offering obligations on generators as envisaged by the Act and GPS. This appendix should be used as an example of the practical implications of specifying mandatory volumes of hedge cover. There are a number of complex issues related to the mandatory offering regime. The purpose of this appendix is to outline some of the difficulties and problems with implementing a workable regime.

1383. The rest of the Appendix covers the following issues:

a. *Offer volumes* – should offering obligations be specified in gross or net terms, what base should be used to determine offer volumes, what percentage of the base should be required to be offered by generators, and should offers be specified on a monthly, quarterly, or annual basis;

b. *Participation* – who should be required to offer contracts, and should there be any restriction on who can be a counterparty;

c. *Sales method* – should there be restrictions on the method parties use to present their offers, and obligations on how they structure their offers;

d. *Types of contracts* – should there be restrictions on the type of contract eligible for meeting mandatory offering obligations, such as transmission hedges, options, etc;

e. *Contract provisions* – should there be restrictions on the terms and conditions of mandatory contracts, such as in regard to profile, location, duration, minimum amount, credit, suspension and force majeure (FM) clauses, etc;

f. *Price determination* – should there be restrictions on the way that contract prices are determined, such as the use of market-clearing prices and reserve prices;

g. *Administration of the regime* – how should offer obligations be updated, how should compliance with offering obligations be monitored and enforced, who should do the monitoring and enforcement, and what penalties should apply to parties breaching the obligations; and

h. *Conclusions*.

10.5.2 Offer volumes

1384. This section considers whether net generation levels should be based on:

a. Net or gross generation levels;

b. Purely historical information for each generator or adjusted for their estimated generation and load growth, and changes in their mix of generation capacity;

c. Dry year generation levels or average generation levels;

d. Whether contract obligations should be specified in monthly, quarterly, or annual terms; and

e. The percentage level of the obligation relative to the above factors.

Should offering obligations be imposed on net or gross generation levels?

1385. A significant issue for a mandatory offering mechanism is whether the required volumes should be based on a gross level or a net level. The gross approach means each generator will have to offer contracts for a percentage of their total generation levels. The net approach means each generator will have to offer contracts for a percentage of their net generation levels – that is, generation less retail load.

1386. Under the gross approach, generator/retailers would be allowed to participate in tender processes, which means they may purchase contracts from other generators or from themselves. If this was not allowed, generator-retailers would be incentivised to reduce their retail and already-contracted load to a quantity less than the remaining percentage of their gross generation, which would harm competition in the retail market. For instance, if mandatory obligations were set at 20 percent of gross generation, generator/retailers would be incentivised to reduce retail load to no more than 80 percent of their gross generation to ensure they have sufficient ability to manage risk internally. Shedding retail customers is not the type of behaviour normally associated with promoting competition in the retail market.

1387. Alternatively, if mandatory obligations are specified on a net basis, generators will be incentivised to increase their retail load to a level closer to their gross generation. For instance, if the level was set at 50 percent of net surplus generation, the generator/retailers may be incentivised to hold a larger amount of retail load to minimise the amount they will be required to offer by tender.

1388. On balance, the net approach is likely to be more efficient and effective than the gross approach, as it is likely to be less intrusive in the internal risk management of generator/retailers. For example, even if the retailing arm of generator/retailers are allowed to purchase contracts through the mandatory market, generator/retailers are left exposed to the risk of their retailing arm buying contracts at prices that differ from the prices received by their generator[36].

1389. In practice, it may be slightly more difficult to estimate net generation than gross generation, as net generation is the residual from movements in two large variables – generation and load. Nevertheless, in New Zealand gross generation is highly variable on a per company basis anyway, given the reliance on hydro-inflows.

Should offer volumes be based on historical or future net generation levels?

1390. An important question is whether mandatory offer volumes should be based purely on historical generation levels, or whether estimates of future generation levels should be used to determine offer volumes.

[36] Although this problem could be avoided by adopting market-clearing pricing, doing so would introduce other complications that should be avoided. See the discussion on pricing later in this section.

1391. The ideal approach would be to base offer volumes for the next year on accurate estimates of next year's net generation levels. This would ensure the regime took full account of the commercial position of each generator, treating each of them neutrally and fairly. In practice it is not be possible to achieve this ideal because forecasts of future net generation levels are likely to contain large inaccuracies, especially when conducted on a per generator basis. In practice, trade-offs have to be made between the objectiveness and currency of the contract obligations. However, a firm obligation means that parties would be more likely to need to continually refine their contract positions as circumstances change, which should in turn lead to increased market liquidity.

1392. The most objective approach would be to use a simple historical formula, updated annually or quarterly. For example, net generation levels for a generator could be calculated on a rolling average basis for the past five years. Although this approach would introduce considerable lags between changes in the commercial position of generators and their contractual obligations, it avoids regulators making judgements about future generation and load patterns.

1393. Another option would be to adopt a more forward-looking approach, which would adjust the historical formula for large one-off factors such as above normal plant outages, and from the acquisition, divestment, or retirement of plant.

1394. Adjustments could also be made for additions of new generation capacity, although such estimates would be much more subjective as dispatch volumes would be unknown until historical experience is gained with them. The same applies to incremental load growth, where one generator/retailer may gain market share over a couple of years and then incrementally lose that position to another party.

1395. The problem with the forward-looking approach is that it introduces a high degree of regulatory judgement into the risk management market, making the mandatory offering regime less transparent and more costly to administer and comply with.

1396. On the other hand, the problem with the purely historical approach is that the offering obligations may be poorly related to the commercial position of each generator. This is likely to place considerable pressure on the Commission to agree ad-hoc changes to estimated future net generation levels, or risk undermining industry support for the regime.

1397. For the purposes of evaluating the mandatory offering initiative, we assume the simple historical formula is adopted, with adjustments for large one-off factors but not for incremental load growth. To address the risk of commercial risks undermining industry support for the regime, the mandatory offering initiative would include a generic provision for the Commission to make further one-off changes to estimated net generation levels, provided such adjustments are open to industry scrutiny before final decisions are made.

Should offer volumes be based on dry year or mean net generation levels?

1398. In theory there is a case for basing offer volumes on dry year levels of net generation because it avoids *the risk* of committing hydro generators to offer contracts when they may have insufficient generation to meet those commitments. If for some reason hydro generators found they have contracted more energy than their dry year net generation levels, they may have to purchase electricity from the spot market during periods when spot prices are particularly high and volatile, or purchase cross-hedges from thermal generators to avoid this exposure.

1399. Conversely, a dry year approach imposes high offering obligations on thermal generators because they produce greater generation during dry years than in normal or wet years. During normal or wet years thermal generators would have to buy from the spot market to meet their contract obligations, but this exposure shouldn't present problems to thermal generators provided spot market prices are determined competitively during normal and dry years.

1400. A fundamental problem with the dry-year approach is that it relies on arbitrary technical definitions of a dry-year. Small (2002), for example, suggested a dry year be defined as a '1 in 10 year' event, whereas the Government currently defines a dry year to be a '1 in 20 year' event. Moreover, the definitions of a dry year become very technical and estimates of dry-year generation for each generator are not particularly robust because relatively few data points are used in the estimation.

1401. For example, the prescribed level of dry-year generation for each generator would depend greatly on assumptions about their mix of generation, which will often be different now than when the data relates to, the statistical basis for defining dry years, and on the pattern of lake levels assumed in the definition of a dry-year. The reality is that a dry-year approach is not particularly transparent or robust, and introduces a high degree of subjectivity to setting offer volumes.

1402. The alternative is to adopt a mean-year generation approach. This could involve calculating average generation levels for each generator over the past five years. Mean generation levels for each generator would be relatively easy to calculate and simple to verify, as assumptions are not needed about lake levels and the mix of generation held by each party.

1403. As in the previous subsection, a key problem with the mean-year approach is that it the offering obligations may be poorly related to the commercial position of each generator. However, a mean-year approach will also mean that parties would be more likely to need to continually refine their contract positions as circumstances (eg inflows) change, which should in turn lead to increased market liquidity.

1404. Again, for the purposes of evaluating the mandatory offering initiative we assume the mean generation approach is adopted, with a generic provision for the Commission to make one-off changes to estimated net generation levels provided such adjustments are open to industry scrutiny before final decisions are made.

Should contract obligations be annual, quarterly, or monthly?

1405. A further issue is whether the contract requirements should be specified on an annual, quarterly, or monthly basis. Adopting an annual basis means generators only need to offer a volume of contracts during a year based on calculations of their total annual net generation for that year. On the other hand, adopting a quarterly (monthly) basis would require generators to meet obligations that vary on a quarterly (monthly) basis.

1406. Adopting an annual basis would leave generators with discretion over the timing with which they meet their obligations. Although generators could exploit this discretion to undermine the regime,[37] the large seasonal swings in hydro and pricing risks in New Zealand means there may be little value in requiring generators to offer contracts

[37] For example, they could choose to offer contracts when parties are least likely to want to buy them, such as during wet winter months, and offer contracts at very high reserve prices during dry winter months to deter take up of them.

during the late autumn and winter months when market participants can judge reasonably well whether a dry year outcome is likely.

1407. On the other hand, electricity demand (at least in aggregate) is significantly higher in winter. In order to take account of the volume requirements of purchasers, it may be more appropriate to have the obligations profiled over the year. This may cause a problem with some generators, as hydro inflow patterns are highly seasonal, and generally higher inflows for some lakes occur in spring. Some of these difficulties could be addressed through cross-hedging with other generators.

Determining the volume of contracts

1408. The above discussion determined that contract volumes should be based on historical net generation levels, calculated on a mean year basis using annual data. Suppose under this approach net generation levels for Generator X were calculated to be 50GWh for 2005. Call this the contract base. The next step is to determine the percentage obligation on Generator X – that is, what percentage of the estimated 50GWh should Generator X have to offer to the market in the form of mandatory contracts for 2006?

1409. In general it would be prudent to begin with relatively modest levels, say 50 percent of the contract base, increasing to a maximum of 80 percent over a three to five year period. The modest start would minimise risks associated with unintended side effects of the regime, and would give market participants time to adjust to the operational aspects of the new regime. Although determining the requirement level is somewhat arbitrary, the 80 percent maximum seems reasonable given the historical nature of the contract base and the fact it is based on mean-year generation levels rather than dry-year generation levels. Higher levels could, of course, be introduced later if experience indicated doing so was more appropriate[38].

10.5.3 Participation Requirements

1410. The previous section argued that offer volumes should be specified in relation to the net generation levels of generators. This section considers the implications for who would be required to offer contracts to the market.

Should all generators be obligated to offer contracts?

1411. In principle, all generators offering energy directly to the spot market should be required to meet mandatory hedge obligations, particularly if the net approach is adopted. Under the net approach, co-generation plants would escape mandatory offering requirements because their net generation position is negative. Likewise, larger generators, such as TrustPower and Todd Energy, would escape the regime because they have more load than generation.

Restrictions on counterparties

1412. An important question is whether generator/retailers should be allowed to purchase mandatory contracts. Clearly, net retailers will need to be able to do so to manage their spot market risks, but it is not obvious that net generators should be allowed to do so. For example, allowing a net generator to bid for their own mandatory contracts

[38] John Small suggested a figure of 95 per cent of dry year net capacity in his paper, but that figure served more as a ‘placeholder’ in his analysis rather than a firm view based on careful consideration of the practicalities of the proposed regime.

would effectively remove the mandatory element of the regime, because they could undo any volume requirements specified by the regulator.

1413. In principle, allowing a net generator to bid for mandatory contracts offered by competitors could result in undesirable gaming behaviour if market-clearing pricing is used to settle contracts (see the discussion on pricing later in this section)[39]. Provided some form of pay-as-you-bid (PAYB) pricing is adopted, and there is no collusion between competing generators, there appears to be no reason to restrict inter-generator contracting. Indeed, cross-hedging is considered by most commentators as socially beneficial.

1414. Requiring generators to offer contracts to purchasers potentially exposes generators to undesired credit risk. Provided the credit obligations specified in mandatory contracts are reasonable to generators, there appears to be no reason to restrict brokers, independent retailers, or directly connected consumers from participating in mandatory contract offers.

10.5.4 Sales Method

1415. Currently generators offer electricity contracts through the over-the-counter (“OTC”) market and through *EnergyHedge*. Also, purchasers sometimes conduct “RFP” processes to solicit offers from generators, which are concluded via OTC-type arrangements.

1416. The GPS and the Act provide for the Commission to recommend regulations that would require electricity generators to offer a minimum volume of contracts by tender, but neither document defines the word “tender”. This paper interprets the GPS and Act as requiring public offers of mandatory contracts whereby purchasers can submit open or closed bids for those offers. This paper also interprets the GPS and Act as giving the Commission the ability to determine the tender process if it believed that was desirable.

1417. On balance, there appears to be little value in specifying any particular tender requirements. With today’s information technology it shouldn’t matter whether mandatory contracts are offered via a single platform or multiple platforms, as parties can access multiple platforms simultaneously. Provided appropriate information disclosure requirements are implemented to inform market participants of offers and traded prices and volumes, electricity generators should be free to use whatever tender arrangements best meets their needs and the needs of their customers.

1418. One potential problem with allowing multiple tenders is that purchasers may have difficulty obtaining the right quantities of contracts across multiple tenders if generators conduct their tenders over the same time periods. These problems shouldn’t be significant, however, as each generator will want to conduct tenders at dates and times separate from other generators to attract maximum participation in their offering to maximise prices. Alternatively, generators may see value in continuously offering mandatory contracts through a single web-based platform like *EnergyHedge*, as this would facilitate price discovery for both sides of the market and elicit maximum participation from purchasers.

[39] Note this risk does not arise in the physical market because generators are only paid for the energy they provide to the market, whereas in contracts markets parties can operate on both sides of the market in ways that artificially boost prices.

1419. The above discussion proposes the tender structure and frequency be left to generators. Alternatively, if the Commission were to specify these matters then it would need to specify the sales or tender platform, contract durations and maturity structures. If a centralised blind tender was adopted, the Commission would need to specify credit and pricing arrangements, and the approach to apportioning contract sales to generators. Doing so would add to the complications identified in this Appendix.

10.5.5 Types of Contracts

1420. Paragraph 76 of the GPS indicates the objective of the mandatory offering initiative is greater liquidity and transparency, which suggests net generators should be restricted to offering only a few standardised contracts under the regime, in an attempt to create market depth and liquidity in those products and to facilitate easier comparison of prices. Net generators would be free to offer other contracts to the market, but such offers would not contribute to meeting their mandatory offering obligations until they became agreed contracts.

1421. On the other hand, the GPS objective of facilitating retail competition and enabling market participants to manage their risks effectively suggests eligible contracts should perhaps be defined permissively.

1422. Although the Act provides for the Commission to specify the terms and conditions of mandatory offerings, the standardised approach would be a very detailed and prescriptive approach, and in practice would be similar to the initiative in section 7.7 on mandatory use of standardised contracts.

1423. For the purposes of evaluating the initiative, this specification adopts the permissive approach as it is less intrusive than the standardised approach and likely to yield larger net benefits or lower net costs. If this specification is assessed to produce net costs, then the standardised approach would be even more negative.

10.5.6 Pricing

Price Setting

1424. John Small's paper suggested that mandatory contracts be settled at market-clearing prices – that is, all purchasers would pay the price of the marginal contract that 'clears the market'. The alternative is to adopt pay-as-you-bid pricing, which is where purchasers and sellers pay and receive the price agreed for each contract, as occurs in most financial markets.

1425. PAYB approaches can be used in one-way auctions conducted by purchasers or sellers, and in two-way auctions where trades only occur when bid and offer prices match. Under one-way auctions conducted by sellers, for example, purchasers would bid into the market the prices they would be happy to pay for contracts, and contracts would be allocated to purchasers based on highest bid price and then in decreasing order down the bid stack[40]. Orders will be fulfilled until the capacity is exhausted, provided the bid price is higher than the reserve price.

1426. On balance PAYB pricing is likely to be more effective and robust than the market-clearing approach. Although the market-clearing approach would be consistent with

[40] In a two-sided market, sellers would offer contracts at prices they would be happy receive, and contract trades would occur when the buyer and seller prices match.

pricing arrangements for the physical spot market, and would provide the correct incentives for purchasers and sellers to reveal their true valuations, it contains risks for financial markets because parties can operate on both sides of the market to artificially inflate prices. Generators, for example, could have incentives to do this to raise the overall prices they receive on contracts.

1427. This conclusion is consistent with the proposal to allow generators to choose their own tender arrangements and processes, which would not be possible under a market–clearing approach to pricing.

Reserve price

1428. Unless Parliament amends the Act, the Minister does not have the ability to introduce regulations setting reserve prices for electricity contracts, even if the Commission recommends such regulations. The reason for this situation is that reserve prices may materially affect contract prices, which could constrain spot prices via arbitrage between the spot and contract markets. Regulating reserve prices, therefore, has the potential to seriously impair the efficient and effective functioning of the spot market, and to undermine the original rationale for having such a market.

1429. Under the current Act, therefore, generators would be free to set reserve prices themselves. If they did not want to sell hedges, generators would have the ability to price their offers out of the market, rendering the mandatory offering regime totally ineffective. On the other hand, if offers were not sold because reserve prices were set too high, there would be increasing pressure on generators to lower the reserve price to something more reasonable.

1430. Given the broader policy risks associated with regulating reserve prices, it would be prudent to adopt a ‘wait and see’ approach to this issue – that is, if the Commission wanted to introduce a mandatory offering regime then it should do so without the ability to regulate reserve prices. If subsequent experience suggests the regime would be more effective with regulated reserve prices, then the Commission could investigate that issue at the time.

10.5.7 Administration of the Mandatory Contracting Regime

1431. To assist monitoring of generator compliance with their offering requirements, net generators would be required to provide information to the Commission on a quarterly basis.

1432. The Commission would provide a form for generators to complete and return to the Commission. The form would request similar information to that required by the initiative in section 6.3 for publishing contract details, but in this case the details would be in regard to contract offers. In addition, the form would request information on historical net generation levels, reserve prices, notice periods, offering method, response rate, and the percentage of offers transacted.

1433. Compliance with mandatory offering requirements would be monitored formally by the Commission, and informally by interested parties. Interested parties concerned about generator compliance with the rules would lodge rule breach allegations with the Commission. The normal process for dealing with alleged breaches, as outlined in the Regulations, would then be followed and the Rulings Panel would have authority to impose fines on parties breaching these rules – particularly for deliberate compliance failures.

10.5.8 Conclusions

1434. The above analysis shows there would be significant difficulties with introducing an effective and workable mandatory offering regime on generators. For example, a workable regime is likely to be based on mean generation levels rather dry year generation levels, and is likely to allow generators to set reserve prices. Both features would appear to render a mandatory regime largely ineffective at forcing greater hedge contracting.

10.6 Appendix F: Technical version of the LRA methodology

1435. Section 7.4.3 in the text presented a simplified version of the methodology for the LRA initiative. This Appendix presents a technical version of the initiative, and uses numerical examples to build understanding of the methodology. The remainder of the Appendix also discusses the implications of choosing alternative load share variables, and discusses key technical issues that would need to be considered if the initiative was pursued further.

10.6.1 The allocation methodology for a single constraint

1436. The simplest case to consider a situation where there are no losses and there is only one circuit constraint binding in the SPD model. In this case rentals would be allocated to spot market purchasers only if they are located at an eligible node. An *eligible node* is any node, m, for which the price at that node, P_m, exceeds a reference nodal price, P_r. That is, eligible nodes are nodes for which $P_m > P_r$. Spot market purchasers at other nodes would not receive any rentals.

The allocation formula

1437. Assume rental allocations are determined for each trading period. In practice rental allocations could be determined on a monthly basis but it is useful to develop the theory on a trading period basis.

1438. Let node n be a specific eligible node – that is, one of the set of m eligible nodes. For a single trading period, the methodology for allocating rentals to spot market purchaser i taking load at node n can be expressed as:

$$R_n^i = (P_n - P_r) \times L_n^i \times A_r \qquad \text{(1a)}$$

Where:

$P_n > P_r$;

R_n^i denotes the value of the rental rebate allocated to spot market purchaser i at node n;

P_n denotes the price at node n and P_r denotes the reference price;

L_n^i denotes the gross load of spot market purchaser *i* at node n; and

A_r denotes a scaling factor that is used to spread the available rent over all loads at eligible nodes. The full description of A_r is discussed further below.

1439. Note the reference node, r, need not be a physical node and more likely would be a notional node corresponding to the desired reference price. This is discussed further below.

The scale factor

1440. The allocation formula includes a scale factor to ensure total rental allocations match available rentals. This is achieved by defining the scale factor as total market rentals available for allocation divided by a measure of the hedging requirement of spot market purchasers at selected nodes (that is, nodes where $P_m > P_r$).

1441. The scale factor is different for each constraint and for each trading period. In mathematical terms, the scale factor is defined as:

$$A_r = \frac{R}{\sum_{m>r}(P_m - P_r) \times L_m} \qquad (1b)$$

Where:

R denotes loss and constraint rentals arising during the trading period and available for allocation under the LRA methodology;

$m>r$ denotes the set of eligible nodes, that is nodes where $P_m > P_r$;

P_m denotes the prices at all eligible nodes – note that P_n is a member of the set of prices P_m;

L_m denotes gross load for any eligible node, m; and

the other variables are as defined above.

1442. The denominator in the above equation is defined as the *total aggregate hedging requirement* of spot market purchasers at eligible nodes, relative to the reference price. To see this, remember that the amount any spot market purchaser i at any node m needs to hedge is their gross load at that node, L^i_m, multiplied by the extent the constraint elevates prices above the reference price, $(P_m – P_r)$. That is, $(P_m – P_r)$ x L^i_m. The total hedging requirement at node m is therefore $(P_m – P_r)$ x L_m. The above formula *aggregates* these outcomes across all eligible nodes, $m>r$, to derive a total aggregate hedging requirement relative to the reference price.

1443. The formula in (1b) is quite general, and allows rentals to be spread thinly across many nodes or to be spread to only the few nodes most affected by grid losses and constraints. These effects depend on the choice of the reference node, which was discussed in section 7.4.4 of the main text, and illustrated further below.

10.6.2 The allocation methodology for multiple constraints

1444. The above discussion assumed a very simple grid configuration. For more complicated grids it is necessary to use differences in participation factors rather than price differences, as explained below.

Participation factors

1445. The concept of participation factors is rather technical, but in simple terms they explain the relationship between a circuit constraint and a node elsewhere in the system. For a given circuit constraint, the participation factor for a node represents the "implicit flow impact" of load at that node on the constraint. Alternatively, the participation factor for a node represents the implicit price impact the circuit constraint has on the price at that node.

1446. If there is only one binding constraint in SPD, and if losses were not modelled within SPD, the price at each node could be explained by a reference price, plus the constraint shadow price times the participation factor for that node. That is:

$$P_n = P_r + PF_n \times S \qquad (2)$$

Where:

PF_n denotes the participation factor for node n;

S denotes the shadow price for the binding constraint; and

All other variables are as defined above.

1447. In simple terms, the *shadow price* of a constraint converts physical effects into value effects. The physical impact of a constraint on a node is given by the participation factor for that node, which tells us how much additional electricity can be delivered to the node if the constraint is relaxed by 1 MW. The shadow price converts that physical impact into the dollar value of relaxing the constraint by 1 MW. This is analogous to the way that the price of a commodity converts the quantity of that commodity into a value. That is, value = quantity x price.

1448. In a simple (unlooped) network, where only one constraint binds during any particular trading period, the participation factors will take values of -1, 0, or 1, and will simply imply a price difference between nodes upstream and downstream of a constraint. This is why the price impact was the same for all nodes in region BCDE in Figure 33 in the main text (section 7.4.3). More generally, though, participation factors will vary around loops, reflecting “spring washer” effects.

1449. Note that losses are not taken into account in the analysis below, but the current view is that it will be possible to develop participation factors that take into account losses, and so the following analysis should readily apply to losses. This will need to be confirmed at a later date if the Commission decides to further consider the LRA initiative.

The generalised allocation methodology

1450. If there are multiple constraints binding in SPD, then multiple participation factors apply to each affected node. In this case, it is not useful to use nodal price differences to allocate rentals because doing so fails to separate the effects of different constraints. These effects are often in quite different parts of the network, for which there are different constraint values, and therefore different rental values to be allocated. This becomes clear in Example 3 below.

1451. As above, let node n be a specific eligible node and let c denote a constraint, of which there are two or more occurring simultaneously. For a single market trading period the methodology for allocating rentals to spot market purchaser i taking load at node n can be expressed as:

$$R^i_{n,c} = S_c \times (PF_{n,c} - PF_{r,c}) \times L^i_n \times A_{r,c} \qquad \text{(3a)}$$

Where:

$R^i_{n,c}$ denotes the rental rebates arising from constraint c that are rebated to spot market purchaser i taking load at node n;

S_c denotes the shadow price for constraint c;

$PF_{n,c}$ denotes the participation factor for node n in constraint c;

$PF_{r,c}$ denotes the participation factor for the reference node in constraint c;

$PF_{n,c} > PF_{r,c}$ for all eligible nodes;

L^i_n denotes the gross load of spot market purchaser i at node n; and

$A_{r,c}$ denotes the scale factor for constraint c, given reference node r, as defined below.

1452. The scale factor in this case is:

$$A_{r,c} = \frac{K_c}{\sum_{m>r}(PF_{m.c} - PF_{r,c}) \times L_m} \qquad (3b)$$

Where:

K_c denotes the MW value of constraint c (ie the right-hand-side in linear programming terminology);

$PF_{m,c}$ denotes the participation factor for node m in constraint c;

$PF_{r,c}$ denotes the participation factor for the reference node in constraint c; and

L_m denotes gross load for any eligible node m.

1453. For simplicity of notation, in the rest of this Appendix we drop the c subscript, but readers should appreciate that formulae (3a) and (3b) apply to a single constraint during each trading period. If there are multiple constraints then (3a) and (3b) would be applied multiple times for each trading period.

1454. For a single constraint situation, we have PF_r = 0, and so ($P_m - P_r$) = ($PF_m - PF_r$) x S. Substituting into (3b) gives the price-based scale factor used in (1b):

$$A_r = \frac{S \times K}{\sum_{m>r}(P_m - P_r) \times L_m}$$

Where S x K is the loss and constraint rentals available for distribution under the LRA methodology – that is, S x K = R from above.

Application of the generalised methodology

1455. Although the allocation methodology appears very abstract, the key terms in that formula are either readily available or relatively easily derived. The L_m variable is available on a trading period basis from settlement data, and the K and S variables are available from the final SPD solution. The r variable is set by policy, as discussed briefly in section 7.4.4 of the main text.

1456. The SPD model does not currently report the PF variables, but it is expected they could be derived from data which the model produces during the solution process, and which is currently not passed through to the operator interface. If they are not available from the SPD model they could be derived, at least approximately, using other computer models. For small examples, such as those discussed below, PF values can be manually derived from line impedances.

10.6.3 Numerical examples of the LRA Methodology

1457. This section of the Appendix builds understanding of the LRA methodology by illustrating first the methodology for a single constraint in a simple part of the grid, and then adding a single constraint to a looped part of the grid. A final example is provided for the case of multiple constraints in a looped system.

1458. As in the main text, consider a hypothetical grid (See Figure 38 below) with:

- five nodes, A, B, C, D, and E;
- all circuits have equal impedance;
- losses are ignored;
- total load is 150MW, with 50MW at node A, 50MW at node C, and 50MW at node E; and
- there are three generators on the grid: a 200MW generator located at A offering into the market at $60 per MWh, a 200MW generator located at B offering into the market at $80 per MWh, and a 200MW generator located at node D offering into the market at $100 per MWh.

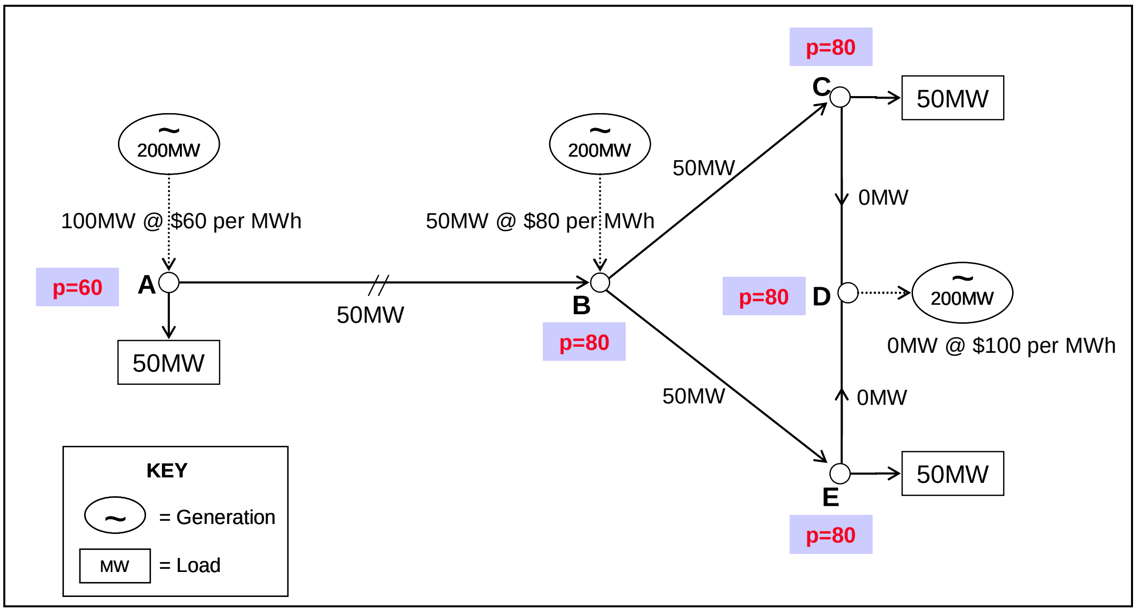
1459. The following examples use the same grid, and similar dispatches, but with different constraints binding, in order to illustrate the allocation theory. The first example is the same as in section 7.4.3 of the main text.

Example 1: A simple constraint

1460. If circuit AB has a security-constrained capacity of 50MW, then as shown in Figure 38:

- the cheapest generator, A, is dispatched to 100MW at $60 per MWh, thus meeting local load with a 50MW transfer to B;
- generator B, the cheapest downstream of the constraint, is dispatched to 50MW at $80 per MWh, meeting all remaining requirements at nodes in the BCDE loop;
- generator D is not dispatched because it is too expensive;
- thus the price is $60 at A, and $80 throughout the BCDE loop; and
- the rentals generated on the AB constraint is 50*20 = $1000.

Figure 38: Example Grid: AB constrained



1461. Intuitively, the rentals on AB should be allocated to loads in loop BCDE, as they are the parties experiencing adverse locational price differences.

The choice of reference price or reference node

1462. The rental allocation among the parties in the BCDE area will depend on the choice of reference price, P_r. In this simple case, the choice may seem obvious. The reference price (or reference node) can't be in BCDE, because all loads in BCDE face the same high price of $80 per MWh. Thus node A seems like the only option, but this is not the case.

1463. For example, the reference price could be set at the load weighted average price (LWAP), which in this example is $73.33 per MWh. Alternatively, the reference price could be set at the generation weighted average price (GWAP), which in this example is $66.67 per MWh. Either option creates a notional node that does not exist, but nevertheless can be used as if it does exist.

1464. One reason for choosing node A as the reference node is that it has the lowest price in the system. In general choosing the lowest price will not be a good basis for allocating rentals because it is likely to allocate rentals to some parties upstream of constraints who actually receive lower prices as a result of the constraint. This is not a problem in this example because the example assumes the AB constraint increases prices in the BCDE loop but doesn't lower prices anywhere on the system.

1465. Another approach would be to set a reference price that is neutral with respect to constraints. Node A fulfils this requirement very well in this example, but in practice it will be difficult to find such a neutral price.

1466. It turns out that in this example all of the above choices achieve the same rental allocations, because all prices in the BCDE loop are the same. Rebates would still only be provided to loads with prices above the reference price, and the scaling factor just adjusts to spread all the available rent evenly between loads in the BCDE region.

Allocation of rentals using node A as the reference node

1467. If node A is the reference node, then $P_r = P_A$ = $60 in this example. Consequently, (P_n - P_r) = $20 for all nodes in region BCDE. As the total BCDE load is 100MW, the total hedging requirement of BCDE is $2000. With total rentals equal to $1000, the scale factor is $1000/$2000 or 0.5.

1468. The rental rebate to load at C is ($80 - $60) x 50MW x 0.5 = $500. The same rebate is provided to load at E in this example, as it has the same price differential and load volume. This reduces the *net price* at both nodes by $10 per MW, from $80 to $70.[41]

1469. Hence, the allocation methodology provides aggregate cover for 50 percent of the potential hedging requirement in the BCDE region. This occurs because the LRA methodology only covers price risk on "imported" power flows, which equal 50 percent of total load in the BCDE region.

1470. Note that if LWAP was used as the reference price in this example, the scaling factor would have to exceed 1 in order to dispose of all the available rent. Although this works, in this case, it would seem unnatural, and potentially anomalous, for nodes "downstream" from the reference node to have a final net price below the reference price.

[41] Note the net price is simply the nodal price less the per MWh value of rentals received. The net price differs from the effective marginal price (used in section 7 of the main text), as it does not take into account the second-order effects of price changes. In terms of consumer and generator behavior, the effective marginal price is the relevant price term to consider.

Allocation using participation factors

1471. If node A is chosen as the reference node, then the AB constraint would be expressed in the form:

$(d_B - g_B) + (d_C - g_C) + (d_D - g_D) + (d_E - g_E) < 50$

Where d and g represent demand and generation at each.

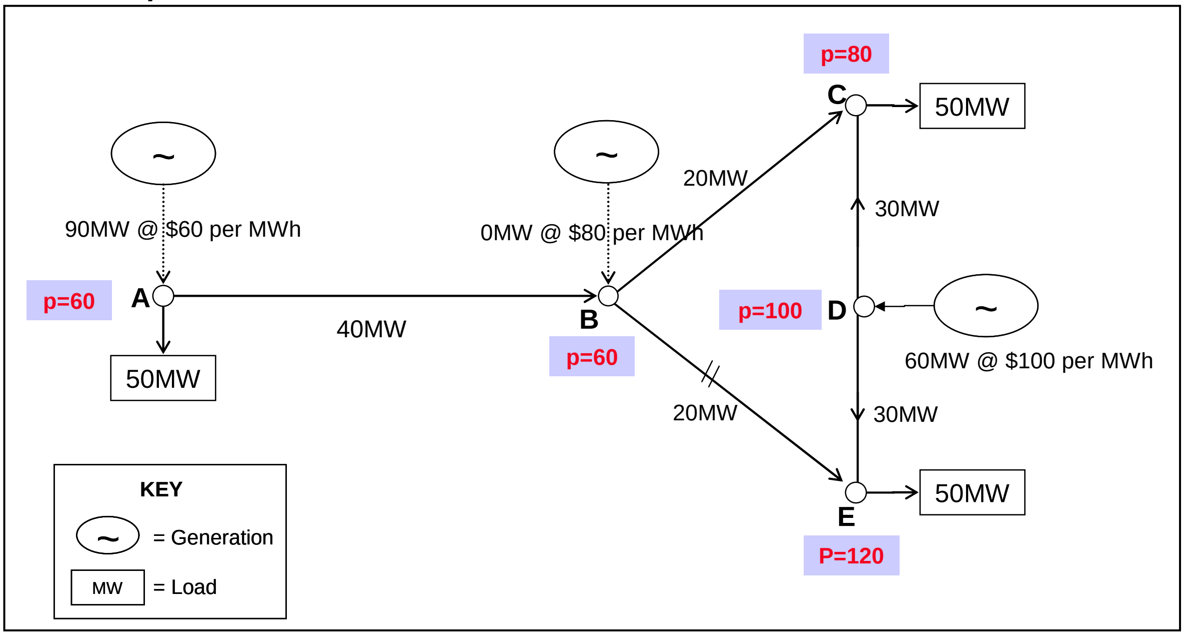
1472. In other words, B, C, D, and E all have PF =1, while PF_r = PF_A =0. As nodes C and E have the same participation factors and the same loads, they each receive half of the rental allocations – that is, $500 each. There are no loads at B and D, so they receive no allocations. Although there is a 50 MW load at A, PF_A =0 and so they receive no rental allocation. This is of course the same result as under the price-based approach.

Example 2: A loop constraint

1473. Now consider a different case, with a 20MW constraint on the flow from B to E, but no constraint from A to B. This changes the situation radically:

- Since flow from A to B is unconstrained, it can freely supply B at $60, thus setting the price at B and backing off all generation there;
- But actually, generation at A is still limited to 100MW, because any more would imply overloading BE;
- In order to balance this, we must bring on more expensive generation nearer the downstream side of that constraint; and
- The generator at D becomes marginal at a price of $100, and the flows are as shown in Figure 39 below.

Figure 39: Example Grid: BE constrained



1474. This sets the price at $100 for D, and implies that prices rise around the BCDE loop, from $60 at B, to $80 at C, to $100 at D, and to $120 at E. The price differential between nodes B and D equals $40, but this is not the constraint shadow price. The shadow price is in fact $80 in this example.

1475. Recall that the shadow price of a constraint is the additional value created by relaxing a constraint by 1 MW. In this case, relaxing the BE constraint by 1 MW would allow one more MW to be delivered to node C at a cost of $60 instead of $80 (saving $20) and one more MW to be delivered to node E at cost of $60 instead of $120 (saving $60). The total resource savings from relaxing the constraint is therefore $80 per MWh.

1476. The total constraint rental available for allocation to spot market purchasers is the MW value of the constraint multiplied by the shadow price of the constraint. That is, 20MW x $80 =$1600.

Choice of reference node

1477. As in the previous example, a reference node has to be chosen for the allocation methodology. The choice is not obvious in a loop structure like this, so for now assume the policy is to choose the lowest priced node in the loop. The lowest priced node in the loop is node B, and so P_r = P_B = $60.

Allocation of rentals using node B as the reference node[42]

1478. The price gaps relative to the reference node are (P_A - P_r) = $0, ($P_B$ - P_r) = $0, ($P_C$ - P_r) = $20, ($P_D$ - P_r) = $40, and ($P_E$ - P_r) = $60. The total “hedging requirement” for each load is $4000 and comprises:

- 50MW x $0 = $0 for A
- 50MW x $20 = $1000 for C
- 50MW x $60 = $3000 for E

1479. The scale factor is therefore:

A_r = 1600 / 4000 = 0.4

1480. Applying the price-based formula in (1b) the load at C is allocated rentals equal to $20 x 50MW x 0.4, which is $400. This reduces the net price at C by $8, to $72. The load at E is allocated $60 x 50MW x 0.4, which is $1200, bringing its net price down by $24 to $96.

Allocation of rentals using other reference nodes

1481. It is insightful to briefly consider the effects of choosing other reference nodes, as they demonstrate that the effects of the LRA initiative depend critically on the choice of reference node.

1482. For example, suppose node C was chosen as the reference node. In this case all of the $1600 rent would be allocated to the load at E, because only E pays a price greater than the $80 price at C. Adopting this approach would reduce E’s net price by $32, to $88. Note the same result would occur, in this case, if LWAP ($86.67) was chosen as the reference price, because only the price at E exceeds $86.67. In general though, LWAP would produce a different price than other reference prices.

[42] In this example, we could equally use A as the reference node, because it has the same price and participation factor as B, but this does not follow through to Example 3 below.

Allocation using participation factors

1483. If node B is chosen as the reference node, then the AB constraint would take the following form:

0.25 x $(d_C - g_C)$ + 0.5 x $(d_D - g_D)$ + 0.75 x $(d_E - g_E) < 20$

1484. This can be derived by considering the proportion of flow which would have to flow over the constrained line in order to meet an incremental MW at each node, from the reference node. This drives the price differences, and also measures the degree of "import dependence" at each node.

1485. In terms of participation factors, we have:

- $PF = 0$ for A,B
- $PF = 0.25$ for C
- $PF = 0.5$ for D
- $PF = 0.75$ for E

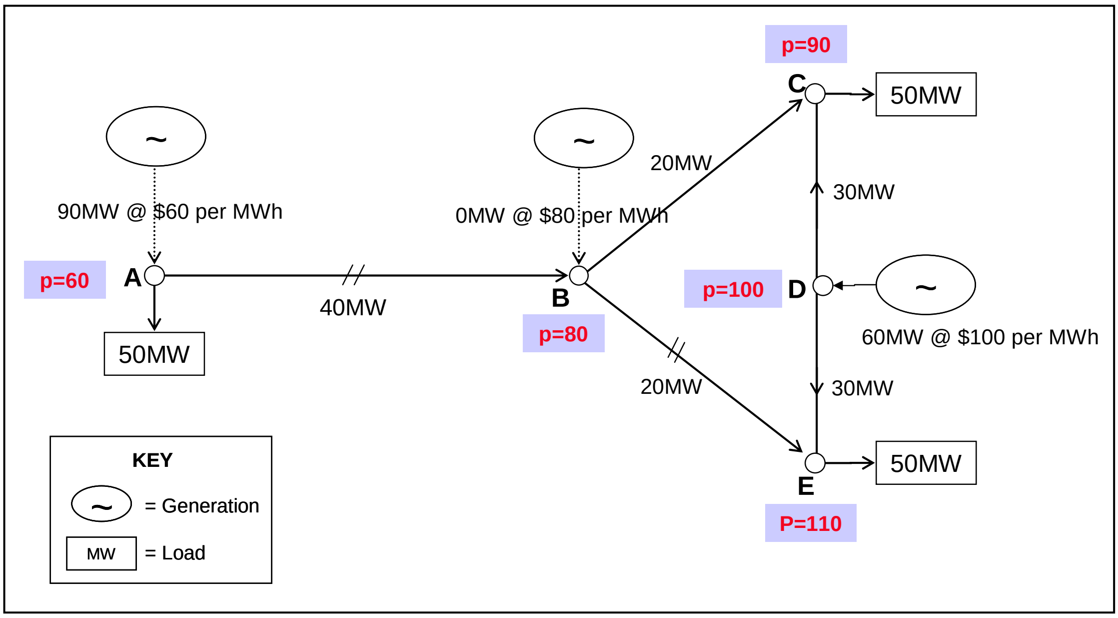
1486. Applying these participation factors gives exactly the same prices and rental allocations as above, for the case where B is the reference node. This is easy to see because the sum of the participation factors for C and E is 1. Hence, the participation factor for node C is one-quarter of the total, and the participation factor for E is three-quarters of the total. As both nodes have 50MW loads, node C receives one-quarter of $1600, which is $400, and node E receives the rest, which is $1200.

Example 3: Two simultaneous constraints

1487. Finally, consider the case where the limit on the AB constraint is lowered to 40 MW, so that both of the above constraints bind simultaneously as shown in Figure 40 below. The dispatch discussed in the previous section actually remains optimal, but the prices change, because the generation pattern required to meet the "next MW" of load is now more constrained than before[43].

[43] Strictly speaking, there would be some price ambiguity at the precise point where the constraint binds, with both price sets being compatible with the dispatch: one for decrements and the other for increments. But, although it is highly improbable that we will actually observe the system in this state, it simplifies the discussion to retain the same dispatch, but with different prices.

Figure 40: Example Grid: AB & BE constrained



1488. Generator A cannot supply any more cheap generation to B, so the price at B must rise but not above the price of $80 offered by Generator B. In fact Generator B now becomes marginal (along with A and D), setting node B's price to $80. The rental collected on the AB constraint is 40MW x $20 = $800, which is a little less than before.

1489. There is also a new set of prices around the BCDE loop, namely $80 at B, $90 at C, $100 at D (which is still marginal) and $110 at E.

1490. The price differential between nodes B and D is $20, but the shadow price is $40 on the BE constraint. To see this, relax the BE constraint by 1 MW. This allows Generator B to supply an extra MW of cheap power to node E (saving $30) and an extra MW of cheap power to node C (saving $10). The total effect is $40. The total rental on the BE constraint is therefore 20MW x $40 = $800[44].

1491. As there are multiple constraints binding in this example, it is necessary to use the participation factor version of the allocation methodology, and it needs to be applied to each constraint separately.

1492. For the AB constraint the calculations discussed above using participation factors carry through identically, except that there is only $800 of rentals on the AB constraint to be distributed to loads in BCDE rather than the $1000 in Example 1. Thus we can still think of BCDE as forming a simple "region" with respect to that constraint, and think of A, for example, as being a reference node with respect to which we are providing partial hedging, to the extent of the "imports" across the AB constraint into that region. So all loads in that region receive a rebate of $8 per MW from that constraint rental pool.

1493. For the BE constraint the calculations discussed above using participation factors also carry through identically, except that the spring washer effect and the rent available from the constraint are now scaled in half. The participation factors for each

44 The spring washer effect here is scaled to exactly half of the previous example, the reason being that, while the AB constraint makes it more difficult to get cheap power to B&C, thus raising prices there, it effectively takes pressure off the BE constraint, thus lowering the price at E.

node in that constraint are the same as for Example 2 (even for node A), and node B can still be the reference node[45]. The allocation formula in equation (3B) will then distribute the rents on the BE constraint, to loads around the BCDE loop, in proportion to their dependence on “imports” (from the reference node) across the constrained line. Thus loads at C get a further rebate of $4 per MW from that pool, while those at E get an extra $12 per MW.

Thus we have:

Net load price at A =	*$60*	*-$0*	*-$0*	*= $60*
Net load price at B =	*$80*	*-$8*	*-$0*	*= $72 (with no load)*
Net load price at C =	*$90*	*-$8*	*-$4*	*= $78*
Net load price at D =	*$100*	*-$8*	*-$8*	*= $84 (with no load)*
Net load price at E =	*$110*	*-$8*	*-$12*	*= $90*

1494. As above, the reference node for the BE constraint could be shifted to C, for example, and the logic outlined above would carry through. In fact, the reference node could actually be shifted even to A, but it is no longer the price at A which would be relevant (since it is now separated from the BCDE loop by another constraint), but rather its participation factor in this particular constraint. So we must use the participation factor based allocation formula.

1495. Note that, no matter how the reference node for the BE constraint is chosen, A will never receive any rebates from rents collected on this constraint, because its participation factor is at most zero. The situation of a node, or sub-system, connected indirectly through a single point in the BCDE loop whose price (participation factor) exceeds that of the reference node is quite different, though. All load in that sub-system would have a participation factor equal to that of the point at which it was connected, and would receive its equivalent share of any rebate. This appears to be the only theoretically consistent outcome, and one that properly reflects the relative dependence of each load on “imports” in this loop flow situation.

1496. Finally, the “net prices” stated above involve potentially significant deviations from strict marginal cost pricing. This implies distortions to efficient price signals for price-taking consumers, but as section 7.4 discusses the rental allocations may improve the efficiency of nodal prices for other consumers.

10.6.4 Choice of load shares

1497. Section 7.4 of the text briefly discussed whether contemporaneous, lagged, or fixed load shares should be used in the allocation methodology. As the analysis is rather involved the implications of using lagged or fixed load shares is presented below.

A one-month lag

1498. Lagging load by one month means that this month’s load decisions affect next month’s rental allocations. If there is a perfect positive correlation between this month’s nodal price differences and next month’s aggregate rentals, then the lag basically has no effect on the effective marginal price signal or on the extent of transmission hedge cover provided by the rental allocation. The only effect would be

[45] Actually, in this case, we can still think of hedging with respect to its (unrebated) price. But that is because the other constraint was a simple one, which only shifted all prices in BCDE by a constant. The situation would be more difficult with two loop flow constraints.

the extent that future revenue has to be discounted, which is a tiny value on a monthly basis. For all intents and purposes, the contemporaneous outcome would prevail.

1499. At the other extreme, if there is zero correlation between this month's nodal price differences and next month's aggregate rentals, then rental allocations become a random variable for spot market purchasers, in which case the rational approach is for them to calculate the average monthly value of rentals. They know that on average they receive a share of that value, and they know they receive a smaller share if they reduce this month's consumption levels.

1500. Hence, even in this case, adopting the one-month lag reduces effective marginal price signals. It provides some transmission risk cover to spot market purchasers, but one that is less related to their actual locational price exposure. This introduces a new source of economic inefficiency.

Other options

1501. The other options are to choose longer time lags for the load variables, or to choose other ways of apportioning the rentals, such as in proportion to the customer bases of spot market purchasers. Although these options would further weaken the impact on marginal pricing signals, they would also undermine the hedging value obtained from the LRA initiative.

10.6.5 Technical issues with the allocation methodology

1502. In addition to the policy issues considered in section 7.4.4 of the main text, there are some important technical features of the LRA that will need to be decided if the initiative is to be further developed. These issues relate primarily to:

- the degree of aggregation across constraints; and
- the extent of aggregation across time – that is, should the methodology be applied on a trading period or monthly basis?

Aggregation across constraints

1503. The generalised allocation methodology in (3a) and (3b) above applies to each constraint on a trading period-by-trading period basis. Further work would be required to determine the most efficient means of implementing the methodology to cope with multiple constraints, etc.

1504. An alternative approach to allocating rentals on a nodal basis is to allocate them to pre-defined regions. This approach would ignore the fact that multiple constraints can bind simultaneously, often affecting quite different parts of the network. It would also ignore the fact that the constraints affecting a node may be quite different in different periods, making it potentially difficult to define a stable set of regions.

1505. The implication of the regional approach is that rents collected with respect to one constraint would be shared with participants affected by quite different constraints. At one level this seems undesirable from the perspective of economic efficiency and providing appropriate levels of transmission risk cover. On the other hand, it might be argued that risk sharing per se is desirable and that this is one way to achieve it.

Aggregation across time

1506. The above methodology applies to grid configurations related to half-hour trading periods, but the payments of rental allocations would occur on a monthly basis. There appear to be two options here: (1) apply the methodology on a trading period basis but pay the rebates on a monthly basis; or (2) apply the methodology on a monthly basis by calculating monthly averages for the participation factors, loads, and so on.

1507. The first method is likely to produce the most accurate results but the second approach may assist with sharing risk between time periods, which is the essence of hedging anyway.

1508. It is pertinent to note that Transpower's FTR proposal incorporated deliberate, and relatively elaborate mechanisms to achieve this kind of risk sharing, because it allows a firmer hedging product to be offered. Similar considerations seem relevant here, although the issues have not been investigated in any depth at this stage.

1509. If desired, the LRA could provide a firmer hedge by pooling rents at various levels in the calculations, as discussed above, and scaling rebates to match funds available in the pools. Clearly, the way in which any such aggregation and scaling is achieved would interact significantly with the approach adopted to lagging, if any.