The markets for electricity in New Zealand

Report to the Electricity Commission

February 2007
**Preface**

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NZIER was established in 1958.

**Authorship**

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1. The markets for electricity in New Zealand

What are the markets for electricity in New Zealand? Who are the participants in each market? What are the rules under which they interact? What is the structure of each market in terms of the responsiveness of supply and demand and the level of competition? How do the different markets interrelate?

There exists no single description of the markets for electricity in New Zealand that comprehensively addresses these questions. This publication is aimed to fill that gap. In it, we describe in some detail the current markets for electricity and the “markets” for transmission and distribution services in New Zealand. The level of detail it provides on specific rules and procedures may be more than required by general readers and members of the public. The intended audience is people who need to have a reasonably comprehensive overview and understanding of the actual workings and rules of the various markets and how they interrelate. People who are new to working in the electricity industry or work in one component of it and need to know how that area relates to other components are among those likely to gain most from this publication.

We have drawn on a wide range of sources to provide descriptions of:

- the wholesale spot market for electricity;
- the retail market for electricity;
- the forward and hedge markets for electricity;
- the markets for ancillary services;
- the markets for other electricity market related services;
- the “market” for transmission asset services; and
- the “market” for distribution services.
2. The wholesale spot market for electricity

2.1 Background

2.1.1 NZEM

In October 1996 the New Zealand Electricity Market (NZEM) began operation and since that date the majority of New Zealand’s wholesale trading in electricity for immediate delivery has been conducted through a market. NZEM had one feature which set it apart from the electricity markets developed in other countries. The market was voluntary and the rules of the market were developed by the market participants. Enforcement of the rules depended on a multilateral contractual relationship between the market participants.

There was no explicit government legislative basis for the rules of NZEM and no specific electricity industry regulator. The general law of contract provided the legal basis and, to the extent that the rules were impacted by general competition law through being an arrangement for “fixing prices”, the Commerce Commission exercised oversight. Government Policy Statements (GPS) issued at various times had guided the development of the rules and their governance arrangements because participants understood that if the arrangements they agreed generally conformed with the GPS, the market would be allowed to be self-regulating.

The NZEM Rules Committee oversaw the development and general operation of the rules and worked to ensure their continuous improvement. Changes in the rules required positive votes by various classes of members. The rules themselves set out the voting requirements. The monitoring and enforcement of compliance with the rules was in the hands of a Market Surveillance Committee (MSC). The members of the Rules Committee and the MSC were appointed by the market participants using procedures that were themselves laid down in the rules.

2.1.2 MARIA

The Metering and Reconciliation Information Agreement (MARIA) was established in April 1994. Its initial emphasis was on specifying technical metering and reconciliation standards, laying down testing standards for meters and approving parties to undertake meter testing, data administration and auditing these functions. In 1999, MARIA also took on responsibility for customer profiling and the registry. Profiling is a system that allows retailers to assess how much electricity a consumer uses in each 30 minute trading period based on the consumer’s “profile”. The registry is the national
database that identifies every point of electricity connection in New Zealand by a unique identifier, called an installation control point (ICP)\(^1\).

In addition to its focus on metering and reconciliation, MARIA effectively allowed parties to trade electricity bilaterally and without using the multilateral NZEM. When NZEM first started in October 1996, approximately seven per cent of electricity was traded in this way. In August 1998, the percentage rose to 20 per cent when the Electricity Corporation of New Zealand (ECNZ) contract to supply the Tiwai aluminium smelter was put into MARIA instead of through NZEM. By 2004, 30 per cent of electricity was traded through MARIA\(^2\).

The MARIA Governance Board oversaw the operation of MARIA and the development of its rules. As in NZEM, changes in the rules required positive votes of various classes of members. The rules themselves set out the voting requirements. Compliance monitoring and enforcement was in the hands of a Conduct Committee. The members of the MARIA Governance Board were appointed by the participants using procedures that were themselves laid down in the rules. The Conduct Committee comprised three members of the NZEM MSC\(^3\). MARIA was terminated on 28 February 2004.

### 2.1.3 Grid Operating Security Policy

When NZEM began operating, Transpower had not published its rules for common physical dispatch of electricity generating stations to ensure demand and supply were maintained in balance real time and the quality of electricity was maintained within defined parameters. Given that generators could seek dispatch through NZEM’s market mechanisms and rules, or outside them, Transpower needed to develop these arrangements. These were first published by Transpower as the Grid Operating Security Policy (GOSP) and later became the Common Quality Obligations (CQO).

In 1999, Transpower and the industry moved to establish the Multilateral Agreement on Common Quality Standards (MACQS). The purpose was to move from Transpower unilaterally setting the CQO to a self-regulating industry structure determining common quality standards of supply, including security. The development of MACQS took some time and although it was completed, it was never

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\(^1\) MARIA (2004).


\(^3\) MARIA (2004), p.9.
implemented as it was overtaken by events. MACQS was a multilateral contractual arrangement.

2.1.4 Caygill Inquiry

Following a change in government in late 1999, a Ministerial Inquiry into the electricity industry, headed by the Hon. David Caygill, was instigated. This reported in June 2000 and recommended the continuation of self-regulation, but the introduction of a unified governance body covering NZEM, MARIA and MACQS.

The Caygill Inquiry report also recommended the wholesale market should be mandatory and that the governance body should have a majority of members independent of the industry and an independent chair\(^4\).

Whilst the Caygill Inquiry report recommended the continuation of self-regulation, it also recommended that, should the industry fail to agree the changes necessary, the government should legislate to achieve the outcome. This aspect was incorporated into the legislation that flowed out of the Caygill Inquiry\(^5\).

2.1.5 EGEC rulebook

The industry established an Electricity Governance Establishment Committee (EGEC) to develop the new unified rulebook. The Hon. David Caygill was appointed to chair the EGEC. A number of working groups were formed to carry out the detailed development work. In April 2003, an industry referendum was held on the new rulebook. This rulebook was largely a consolidation of the provisions of the three predecessor arrangements except:

- the governance structure reflected the recommendations of the Caygill Inquiry as regards unification and independence, and mandatory participation; and
- a new set of rules – Part F – relating to transmission service provision, investment and charging was incorporated; these rules effectively made many transmission services contestable, in line with the recommendation of the Caygill Inquiry.

2.1.6 EGR

The referendum failed to achieve the substantial majority across the various groups entitled to vote that was required for the new rulebook to be introduced. This led the government to move to abandon the self-regulatory approach and instead implement the alternative

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government regulatory approach that had been provided for in the legislation. It established an Electricity Commission (hereinafter “the Commission”) to oversee the New Zealand electricity market and the electricity industry more generally.

Under the Commission regime the rules are known as the Electricity Governance Rules (EGR). The Minister of Energy provided the Commission with its initial set of EGR. Amendments to cater for the fact that the industry was no longer going to be self-regulating were made, but in other respects the core of the initial EGR, including those relating to the wholesale spot market, were effectively what EGEC had developed. Hence they also effectively continued the rules of NZEM as regards the wholesale spot market and common quality issues. The area where the rules developed by EGEC were not adopted as part of the EGR was Part F – the rules relating to transmission investment and pricing methodology.

2.2 Part G – trading arrangements

2.2.1 Overview

Part G of the EGR deals with the trading arrangements that constitute the main features of the wholesale spot market for electricity. It provides for processes by which:

- wholesale generators submit and revise offers and purchasers submit and revise bids for electricity to the system operator\(^6\), which is responsible for determining which generators should generate and how much each should produce at every point in time\(^7\);
- grid owners submit and revise information about the capacities and availabilities of their transmission assets to the system operator;
- ancillary service agents submit offers to provide reserves to the system operator;
- the system operator:
  - prepares and publishes the pre-dispatch schedules;
  - prepares and implements the dispatch schedules; and

\(^6\) In New Zealand, the term “bid” refers to purchases and the term “offer” to sales; buyers “bid” and sellers “offer”. This is the standard terminology of financial and commodity markets. In some other countries the term “bid” is used for both purchases and sales of electricity.

\(^7\) Transpower is both the system operator and asset owner of the grid, but the roles are different.
prepares and publishes forecast prices, forecast reserve prices, dispatch prices and real time prices using an electronic information system;

- the clearing manager holds must-run dispatch auctions;
- the pricing manager collects data and produces provisional prices and final prices; and
- participants provide reconciliation information and the reconciliation manager carries out the reconciliation process.

2.2.2 Bids and offers

The general requirement is that each generator submit to the system operator offers to sell electricity for each trading period of the following trading day for each grid injection point at which it wishes to sell electricity. The offers must be received by the system operator by 1.00pm on the day prior to the trading day to which they apply. Small generating stations with capacity of 10 MW or less are not required to make offers.

Whether this general requirement applies to generators embedded in distribution networks (embedded generators) depends on whether the station has a capacity greater than 10 MW and whether the system operator requires it to provide offers (or alternative information) because it reasonably considers the information necessary to assist it to comply with its principal performance obligations under Part C of the rules and achieving its dispatch objective under Part G.

The general requirement does not, however, apply to wind generators, which are referred to in the rules as intermittent generators. The requirement on them is to submit to the system operator by 1.00pm the day prior to the trading day offers based on their forecast of the electricity which they expect to be able to generate for each trading period of the following trading day.

Generator offers, other than those for intermittent generators, can contain up to five price bands and can be different for each half hour trading period. The aggregate quantity of the offer in each trading period cannot exceed the generator’s reasonable estimate of the quantity of electricity capable of being supplied at the grid injection point by the plant. There is no requirement to offer any volume. There is no limit on the maximum price, but the prices of all offers must be non-negative and the price offered in each band must increase progressively from band to band as the aggregate quantity increases. For intermittent generators, offers can only contain one price band and the price must be either $0.00 or $0.01/MW.
Generator offers can be specific as to the generating unit to which they relate or they can be specific to individual generating stations. The installed capacity and the maximum ramp-up and ramp-down rates of the generator in MW hours are specified in the offer. The ramp rates relate to the speed at which electricity output from the generator can be changed.

For each trading day, each purchaser must submit to the system operator its bids to purchase electricity for each trading period of the following trading day at each grid exit point at which it wishes to purchase electricity. The bids must be received by the system operator by 1.00pm on the day prior to the trading day to which they apply.

Purchaser bids can contain up to 10 price bands for each trading period. The bids for each trading period must represent the purchaser’s reasonable endeavours to predict the quantity of electricity which will be demanded at the grid exit point by the purchaser during the trading period. There is no requirement to demand any volume. There is no limit as to the maximum price, but the prices of all bids must be non-negative.

In general, generators and purchasers are able to revise or cancel bids and offers up to two hours prior to the beginning of the trading period by submitting a new bid or offer or a notice of cancellation to the system operator.

Embedded generators that are required to submit offers must use reasonable endeavours to submit any revised offers at least two hours prior to the beginning of the trading period, but are able to revise and cancel offered quantities, but not prices, up to 30 minutes prior to the beginning of the trading period.

Intermittent generators are required to submit any revision to their offer price at least two hours prior to the beginning of the trading period and must revise the quantity of each offer during the two hours immediately before the start of the trading period. Each revised offer must be based on a persistence model using actual output from the generating station at the time the revised offer is submitted. Intermittent generators may cancel offers up to 30 minutes prior to the beginning of the trading period.

In addition, purchasers and generators (other than intermittent generators) are required to submit immediately revised bid or offer quantities if, prior to the beginning of the trading period:

- the quantity expected to be purchased changes by more than the smaller of 20 MW or 10 per cent; or
• the quantity able to be generated is expected to change by more than the smaller of 10 MW or 10 per cent of the quantity scheduled.

No revised bids or offers are required, however, if the expected change in quantity is less than five MW.

Moreover, provision is made for bids and offers to be cancelled or revised within the two hour (30 minute in the case of embedded generators) window before the trading period begins provided there is a bona fide physical reason or the system operator has issued a formal notice of a grid emergency. Under the EGR, “the Board” (which is more commonly referred to as “the Electricity Commission” and which we abbreviate to “the Commission”) is notified of any revisions or cancellations under this provision and checks for compliance with the rules.

Generators with automatic control plant are not required to provide revised offers, provided that their offers are based on the pre-programmed levels for the plant and the quantity able to be generated by the plant is not expected to vary by more than 10 MW of the scheduled quantity. To qualify for this exemption, the offers must be at zero price.

All final bids and offers become publicly available two weeks after the trading day for which they were submitted. Prior to that they are confidential.

2.2.3 Grid owner information

Each transmission grid owner is required to provide the system operator with information about the capability of all its assets. For the Alternating Current (AC) and High Voltage Direct Current (HVDC) transmission systems, this information has to include the system configuration, system capacity, including the limits of each transmission line, and the system loss characteristics, including transmission loss functions for each transmission line. Grid owners also have to provide the system operator with information on the transformer capacity and loss characteristics, including transformer loss functions of each transformer. The HVDC link connects Benmore in the South Island with Haywards in the south of the North Island and includes the Cook Strait power cables. The AC system comprises the rest of the transmission grid.

This grid asset information has to be updated by 1.00pm on each trading day for the trading periods in the next trading day. Up to two hours prior to the beginning of each trading period the grid owner is
required to submit information to the system operator whenever there has been or is likely to be a change in:

- the information about capabilities, etc.;
- the capacity limit of any transmission line, the HVDC link or any transformer of five per cent or more;
- loss characteristics which causes any loss to change by five per cent or more; or
- the availability of assets forming part of the grid.

A grid owner is only able to update the information later than two hours prior to the trading period in circumstances where a bona fide reason necessitated the change, the system operator has declared a grid emergency or an unforeseen change occurs in the availability of assets which were the subject of a planned or unplanned outage notified by the grid owner to the system operator. The Commission is notified of any updated information provided under this provision and verifies compliance with the rules.

2.2.4 Offering instantaneous reserves

Provided a party has a valid and enforceable contract with the system operator to provide reserve offers in accordance with the rules, it is able to submit reserve offers to the system operator for trading periods of the following trading day. Reserve offers must be received by the system operator by 1.00pm on the day prior to the trading day to which they apply.

Each reserve offer must be a reasonable estimate of the instantaneous reserve able to be provided at the grid exit point or grid injection point specified in the reserve offer. Three sources of instantaneous reserves are recognised: partly loaded spinning reserves, tail water depressed spinning reserves, and interruptible load. Each reserve offer may be for:

- fast instantaneous reserves (available six seconds after event if generation and within one second of frequency falling to 49.2 Hz if interruptible load and able to be sustained for at least 60 seconds);
- sustained instantaneous reserves (available during first 60 seconds and able to be sustained for at least 15 minutes); or
- both.

There may be a maximum of three price bands for each trading period and the price offered in each band must increase from band to band as the aggregate quantity increases. There is no upper limit for prices and no lower limit for the price of interruptible load. For
generator based instantaneous reserves the prices of offers must be non-negative.

The same generating capacity is able to be offered as energy and as instantaneous reserves and for this reason the party making the reserve offer has to identify the generating unit or station to which the energy offer relates. It is the system operator’s responsibility to ensure that the combined quantity of its dispatch instructions for energy and instantaneous reserves do not exceed the capacity of the individual generating unit or station.

The same restrictions, in terms of the window for revising or cancelling offers being two hours in general but 30 minutes for embedded generators, apply to reserve offers as well as to offers. Similarly, quantity changes (but not price changes) can be made within the period when the window is closed provided there is a bona fide physical reason or a grid emergency has been declared. The Commission is to be advised of changes within the closed window period and is required to assess compliance with the rules.

2.2.5 System operator

a) Dispatch objective

The objective of the system operator, in deciding how much electricity each generation plant should be scheduled to produce for dispatch into the grid, is to maximise for each half hour the gross economic benefits for all purchasers of electricity at the grid exit points less the costs of supplying the electricity at the grid injection points and the costs of ancillary services purchased, subject to:

- the capability of generation and ancillary services and the configuration and capacity of the grid and information made available by asset owners;
- the system operator achieving its principal performance obligations under Part C of the rules or a higher level of common quality if one has been agreed bilaterally with participants; and
- the system operator acting as a reasonable and prudent system operator to re-establish normal operations of the power system in the event of a disruption.

b) Modelling system

The modelling system used to make scheduling decisions (SPD) calculates electricity and reserves prices consistent with this

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8 Ancillary services comprise black start, over frequency reserve, frequency keeping, instantaneous support and voltage support. For a description of these services see Section 5 below.
objective function and consistent with the quantities of electricity and instantaneous reserves scheduled. In particular, the model ensures for scheduling purposes:

- prices are consistent with transmission system losses and the transmission system power flow;
- a generator will be scheduled to generate a quantity of electricity from a price band only if the price determined by the modelling system at the grid injection point adjusted for the marginal load factor at the grid injection point is greater than or equal to the price offered in that price band;
- a purchaser will be scheduled to purchase from a price band only if the price determined by the modelling system at the grid exit point adjusted for the marginal loss factor at the grid exit point is less than or equal to the price bid for that band; and
- a provider of ancillary services that has made a reserve offer will be scheduled to provide a quantity of instantaneous reserves from a reserve price band only if the reserve price determined by the modelling system is greater than or equal to the total price offered for that reserve price band.

When it comes to the actual dispatch of generators, the physical requirements of ensuring that supply and demand are appropriately balanced in real time means that there may occur dispatch of some generators and providers of reserves out of their merit order according to their cost of meeting demand. At present, security constraints, which may give rise to out of merit dispatch, are incorporated into the dispatch schedule partly using computer systems and partly by more manual methods. The process can be protracted.

c) Pre-dispatch schedules

The system operator prepares pre-dispatch schedules for each trading period commencing at 1.00pm the day before the trading day. It uses reasonable endeavours to reduce the time between the commencement of the preparation of each pre-dispatch schedule and to ensure that no more than two hours elapse between the times of commencement of preparation of each consecutive pre-dispatch schedule.

The procedures and mathematical formulas for undertaking the optimisation to determine dispatch prices and quantities are set out in a schedule to the rules. Each pre-dispatch schedule specifies for each trading period covered by the schedule:

- the expected average level of electricity output for each generating plant or unit;
the expected average level of instantaneous reserve from each generating plant or unit;

the indicative frequency keeping generating station for each island;

the expected average level of demand for each grid exit point;

forecast prices for each grid injection point, each grid exit point and the Haywards and Benmore reference nodes;

forecast reserve prices for each island;

forecast marginal location factors for each grid injection point and each grid exit point;

the expected largest single reserve risk for each island;

stacks of fast instantaneous and sustained instantaneous reserve offers for each island;

stacks of fast instantaneous and sustained instantaneous reserve offers for each island, adjusted for the expected level of energy output for each generating plant or unit;

the expected HVDC component flows; and

the expected HVDC risk offsets which are applied by the system operator to the HVDC flows to determine the relevant reserve risk on the HVDC link.

To deal with the difficulties of dispatching hydro stations that are part of a chain, the rules permit a generator to agree with the system operator to treat a group of stations on one continuous water course as a block dispatch group. This means that the dispatcher treats the various stations as one unit for the purposes of dispatch and the generator then decides itself which stations it will use to fulfil the dispatch instructions.

A generator may also elect to have its generating plant dispatched as a station dispatch group. It is not necessary that the generating units inject into the same grid injection point to form a station dispatch group, although if they do not, the agreement of the system operator is required for them to be classed as a station dispatch group. Again, the impact is for the system operator to treat the generating units that are part of a station dispatch group as one entity and for the generator to decide which particular units it will use to fulfil a dispatch instruction.

Once the system operator has completed a pre-dispatch schedule, the system operator publishes electronically for each trading period:

the expected aggregate supply and demand curves at Benmore and Haywards;
• the grid injection and exit points which are disconnected or where an infeasible situation has occurred;
• the expected largest single reserve risk for each island;
• the instantaneous reserves level for each island;
• the reserve offer stack for each island;
• the indicative frequency keeping stations for each island;
• the expected HVDC component flows; and
• the expected HVDC risk offsets.

At the same time, the system operator sends to each purchaser and each generator information from the current pre-dispatch schedule relating only to their demand or generation.

d) Dispatch prices and quantities

To aid generators and purchasers to manage their resources the system operator prepares and publishes at or just before each trading period begins a schedule of dispatch prices, dispatch quantities, dispatch arc flows\(^9\), dispatch group constraint arc flows\(^{10}\), group constraint formulas\(^{11}\) and HVDC component flows\(^{12}\). The information covers the current trading period and at least the next seven trading periods, or four hours. These are calculated using the same mathematical formulas and optimisation objective as the pre-dispatch schedules.

e) Dispatch instructions

In the trading period after a new dispatch schedule arises, the system operator develops and issues dispatch instructions using the current price order in the latest dispatch schedule, the actual profile of demand from the previous trading period and the expected profile of demand within the current trading period and subsequent trading periods. These demand forecasts are developed by the system operator.

The dispatch instructions issued by the system operator instruct a generator to carry out one of the following:

\[^9\] The dispatch arc flow for a line or transformer is the quantity of energy flow over it that is equal or greater than 95 per cent of its maximum flow limit in megawatts.

\[^{10}\] A dispatch group constraint arc flow is similar to a dispatch arc flow but for a dispatch group.

\[^{11}\] A group constraint formula is the mathematical formula applied by the system operator to constrain the energy flows on a group of transmission lines and/or transformers.

\[^{12}\] The HVDC component flows are the quantity of energy flow on each component of the HVDC link.
provide, increase or decrease active power;
provide, increase or decrease instantaneous reserve;
provide an amount and quality of reserve power to regulate frequency continuously;
provide, increase or decrease reactive power;
adjust transformer tap positions to maintain voltage levels;
provide, increase, decrease or maintain voltage;
synchronise or de-synchronise generating plant;
switch on or switch off schemes for over frequency tripping where such capability exists;
manage the generating plant within a block dispatch group or station dispatch group so as to ensure the largest single reserve risk within the group does not exceed the reserve risk for the island notified by the system operator;
manage block security constraints within a block of station dispatch group so as not to exceed constraints; and
manage total aggregate generation within a block or station dispatch group so as not to exceed the total sum of the dispatched quantities for the group.

In addition, the system operator can issue dispatch instructions to those that offered interruptible load into the reserves market to arm or disarm interruptible load or to disconnect or restore demand.

The parties which receive dispatch instructions are required to comply with dispatch instructions properly given except where:

- the instruction contravenes the law or places personnel or plant safety at risk;
- the plant is responding to an automatic signal to activate capacity reserve, instantaneous reserve or over frequency reserves;
- the adjustment to comply with the instruction would be less than one MW; and
- the generator is an intermittent generator and the system operator has not advised that there is a grid emergency or system constraint affecting the generator.

Where the dispatch instructions relate to the ancillary services of instantaneous reserves, voltage control and over frequency tripping, the compliance with the dispatch instructions is only required if the party receiving them has a valid contract to provide them and the instructions conform with that contract or compliance with the instruction is needed to restore power or achieve the asset owners performance obligations under the rules.
f) Real time prices

As soon as practicable the system operator will publish a set of real time prices giving the price of electricity at each grid exit and grid injection point on a five minute basis. These are calculated using the same mathematical formulas and optimisation objective as the pre-dispatch and dispatch schedules.

Along with the real time prices, the system operator publishes information on the extent to which capacity constraints on lines, grid points, and ramp rates occurred and the number of grid exit points at which demand was estimated. The system operator also publishes for each grid injection point and grid exit point a time weighted average of the five minute real time prices for each 30 minute trading period.

The real time prices are indicative only and are not used in the settlement and clearing processes. They are produced to give participants better information on likely market prices.

Where a purchaser intends to increase or decrease its total demand in response to real time prices by greater than 50 MW in any 15 minute period in the North Island, or greater than 30 MW in any 15 minute period in the South Island, the purchaser is required to give the system operator five minutes notice by telephone and manage any change in accordance with the system operator’s instructions.

g) Grid emergency situations

In a number of circumstances the system operator may declare a grid emergency. The effect is that generators and those offering instantaneous reserves are unable to reduce the aggregate quantity of electricity or reserves at any grid connection point except where it has a bona fide physical reason. Generators and reserve providers are able to shuffle quantities between grid connection points and are able to increase the quantities offered.

Moreover, in a grid emergency situation, purchasers are not able to increase quantities except with a bona fide physical reason but can decrease them and shuffle them between grid exit points.

Within 12 hours of a grid emergency ending, the system operator must provide the Commission with a written report setting out its reason for declaring an emergency. The Commission is also informed of any reductions in quantities offered or increases in aggregate bids and assesses whether they complied with the bona fide physical reason requirement.
2.2.6 Must-run dispatch auction

The clearing manager holds a must-run dispatch auction every day. If a generator’s bid at an auction is successful, the generator is authorised to offer electricity at zero price for the time block and trading period for which it was successful. The rights are transferable and the generator holding the right gets to choose the generating plant and injection point at which the right is used. This provision allows a generator that wants to be certain that a particular plant will be dispatched to buy the right to ensure that it does. The auction revenue paid by generators is distributed to purchasers pro rata to their purchases of electricity in the time block to which the auction revenue relates.

The quantity of rights available at the auction in each time block is based on 80 per cent of the lowest demand in any trading period relating to the time block on the same day in the preceding year. The clearing manager notifies each generator of the quantity of auction rights available by 11.00am on the day prior to the auction. Generators lodge bids by 9.00am on the day of the auction and may revise or cancel bids up to that time. A generator may make up to five auction bids for each time block. The highest auction bids are successful and rights are allocated from the highest downwards until all the available rights are allocated. If there is more than one bid at the same price and not enough rights to satisfy both, the auction rights are allocated on the basis of which bid was received first by the clearing manager. Results are notified by 11.00am on the auction day.

2.2.7 Provisional and final pricing

The pricing manager is responsible for collecting data and producing and publishing final prices for electricity and reserves or, if final prices are not able to be calculated, producing and publishing provisional prices.

These prices are calculated using the same mathematical formulas and optimisation objective as the pre-dispatch and dispatch schedules and real time prices. The input information on this occasion, however, is:

- data specifying the instantaneous MW injection at the grid injection point at the beginning of each trading period for all items of generating plant or generating units that were the subject of offers for that trading period, or a reasonable estimate of such data;
- the actual metered half hour supply and demand at each grid connection point and grid exit point adjusted for losses and embedded generation; these data relate to the quantity of
electricity over the trading period, whilst the instantaneous MW injection data relate to the rate of flow at the start of the period;

- the final offers for each trading period submitted by generators after removal of all offers from intermittent generators;
- the final reserve offers for each trading period; and
- the information relating to the bids and offers in each trading period the system operator sends to the pricing manager and the clearing manager each day.

Provided that three conditions hold, the pricing manager proceeds to calculate and publish final prices and final reserve prices for each node and each trading period. This is done by 12 noon the day after the trading day. The three conditions are:

- no infeasibility situations arose in calculating prices using the mathematical formulas;
- the information from SCADA, the computer system for remotely monitoring grid flows, is complete or has been estimated by the grid owner; and
- no material metering information is missing.

If one or more of these three conditions is not met at any node for any trading period during the day, a provisional pricing situation exists and the grid owner is required to exercise reasonable endeavours to rectify the situation. If the grid owner provides revised data that do overcome the problem, the pricing manager calculates and publishes final prices and final reserve prices.

If the revised data also give rise to a provisional pricing situation, the pricing manager publishes the new provisional prices. If no new data are received, the pricing manager publishes a notice and the original provisional prices by 12 noon. Further work is done that day and the next day by the pricing manager and the grid owner to try to rectify the situation, including manually creating prices for those periods affected by infeasibility. These are published by 6.00pm the next day. The Commission is notified every time the grid owner is notified of an unresolved provisional pricing situation and is required to urgently address the matters raised in the notice.

### 2.2.8 Constrained off amounts

Generators that offered electricity at a price below the final price at the relevant grid injection point for a trading period, but were not dispatched, and generators that were not dispatched to the level expected on the basis of their offer relative to the final price, are said to have been constrained off. Generators are not entitled to compensation for being constrained off but the loss of revenue due to
being constrained off for each generator is calculated monthly by the clearing manager and published.

Any generator or purchaser who reasonably believes it was adversely affected by a constrained off situation occurring, or the Commission, may request information from the system operator, and the system operator is required to comply but is not allowed to release confidential information on another generator or purchaser.

If the constrained off situation arose due to voltage support requirements, the system operator is allocated as a cost the total constrained off amount for the occasion. If it was due to a non-security constraint or frequency keeping requirements, the system operator is allocated as a cost the proportion of the constrained off costs that the non-security constraint or the frequency keeping accounted for of the total quantity of electricity constrained off.

2.2.9 Constrained on amounts

Generators that offered electricity for dispatch at a price above the final price at the relevant grid injection point for a trading period, but the offered electricity was dispatched anyway, are said to have been constrained on. Generators are entitled to be paid compensation for constrained on amounts at the final price for the grid injection point.

The constrained on amounts for each generator are calculated monthly by the clearing manager and published. Any generator or purchaser that reasonably believes that it was adversely affected by a constrained on situation occurring, or the Commission, may request information from the system operator, and the system operator is required to comply but is not allowed to release confidential information relating to another generator or purchaser.

If the constrained on situation arose due to voltage support requirements, the system operator is allocated as a cost the total constrained on amount for the occasion. If it was due to a non-security constraint or frequency keeping requirements, the system operator is allocated as a cost the proportion of the constrained on costs that the non-security constraint or the frequency keeping accounted for of the total quantity of electricity constrained on.

The constrained on compensation not attributed to the system operator is recovered through the normal invoices from purchasers pro rata with their share of purchases during the trading period the constrained on event occurred.
2.2.10 Reconciliation

The reconciliation manager gathers information from a variety of sources:

- purchasers are required to provide the reconciliation manager with information about the grid exit points at which they purchase electricity and the metered and estimated quantities of electricity they or their customers consume;
- generators are required to provide the reconciliation manager with information about the grid injection points at which they intend to sell electricity and metering information for each generating plant at each point of connection to the grid and a local network;
- the grid owner provides the reconciliation manager with metering information for each grid exit point;
- the system operator notifies the reconciliation manager of disconnected grid injection points and grid exit points; and
- each distributor is required to provide the reconciliation manager with the loss factors relevant to each loss category for each of its networks and will also nominate a grid exit point at which supply will be deemed to have been taken when there is or maybe uncertainty about the actual grid exit point at which supply will be made.

The reconciliation manager takes this information and for each reconciliation period calculates from it information about the quantities attributable to each generator and the quantities attributable to each purchaser relating to trading in the reconciliation period. Each month the reconciliation manager provides to generators and purchasers the information relating to them. It provides to the grid owner the information it requires to calculate its charges and to the clearing manager it provides the reconciliation information it requires to calculate the amounts payable by it to each generator and each purchaser. Other parties can also have access to some information in certain circumstances.

The reconciliation manager receives revised consumption information from purchasers when more meters are read and errors in previous readings are corrected. It uses this information to revise its calculations and distributes the revised information to the various parties. Revised calculations are produced in months one, three, seven and 14 after the initial calculations, and at 18 and 24 months if...

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13 New rules in relation to reconciliation have been approved by the Minister of Energy. These do not come into force until 1 May 2008. Key features of the new rules are the elimination of the role of an incumbent retailer in an area, the grouping of grid exit points for reconciliation and the facilitation of gathering information on embedded generators. For details see: http://www.electricitycommission.govt.nz/rulesandregs/rulechanges
requested. No disputes about metering installations and consumption information are able to be raised after 24 months.

2.2.11 Clearing and settlement

The clearing manager:

- sets and administers the prudential requirements imposed on parties required to make payments for electricity or ancillary services;
- calculates the amounts that purchasers owe for their purchases of electricity and the amounts that generators are entitled to receive for the electricity they sold;
- calculates the amounts participants have to pay for ancillary services;
- receives and makes payments for electricity and ancillary services;
- may receive and make payment in relation to the settlement of hedge settlement agreements\(^\text{14}\) lodged with it; and
- pays the loss and constraint excess to Transpower as the grid owner.

The prudential requirements can be satisfied by maintaining an acceptable long-term credit rating of A- or better under Standard & Poor's classification or the equivalent from another approved rating agency. They can also be met by providing cover of at least the minimum amount set by the clearing manager in the form of:

- a cash deposit;
- an unconditional guarantee or letter of credit in favour of the clearing manager from a bank or third party with an acceptable credit rating;
- a security bond in favour of the clearing manager;
- lodgement of hedge settlement agreements with the clearing manager for settlement with the clearing manager (the clearing manager values these agreements for prudential purposes);
- provide security approved by the Commission; or
- provide a mixture of security or take other account acceptable to the Commission.

The minimum level of cover required is set at least weekly by the clearing manager and is based on the potential liabilities to the market the payer could accumulate before it should be known the payer has defaulted.

\(^{14}\) Hedge settlement agreements are used by buyers and sellers to manage the risks of movements in the price of electricity.
The clearing manager sends out the invoices to those liable to pay for electricity and/or ancillary services. Payment is due on the 20th of the month and must be in the form of bank cleared funds. The clearing manager pays those to receive the money when it receives the money. If there is a shortfall in payments received because of a default by a payer, the clearing manager reduces the payments to generators pro rata to their share of total payments for electricity for the billing period to which the default relates.

The loss and constraint excess is the amount by which the payments receivable by the clearing house from purchasers for electricity they purchased during the billing period exceeds the amount payable by the clearing house to generators for the electricity they generated during the billing period. The clearing manager pays these sums to Transpower as grid owner, but Transpower currently passes on the payments to its customers on the basis of the transmission charges they pay.

### 2.3 Generators and generating capacity

#### 2.3.1 Market structure

Six generators own the bulk of New Zealand’s generating capacity. Three of these are State-Owned Enterprises (SOEs) – Meridian Energy, Genesis Power and Mighty River Power. Two are privately owned and listed on the New Zealand Exchange – Contact Energy and Trustpower. One, Todd Energy, is privately owned and unlisted. Between them, these six companies account for well over 90 per cent of New Zealand’s generating capacity.

The balance of the capacity is made up of co-generation facilities servicing large industrial clients, renewable energy plants, including several owned by distribution companies, and standby generators in hospitals, ports, industrial plants and the like. A number of the standby plants are able to export into networks, and do so in some situations. There is also a 155 MW liquid-fuel reserve energy plant at Whirinaki, near Napier. This is owned by the government, operated by Contact Energy, and controlled as regards it offer strategy into the wholesale spot market by the Commission.

Some of the small generators are not market participants under the rules. Generating stations with capacity of 10 MW or less are not required to make offers into the wholesale spot market, although they can and their owners may be market participants.

If a generating station has a point of connection to the grid, the electricity it generates must be sold to the clearing manager and the
clearing manager must purchase it. The output of an generating station embedded within a distribution network must be sold to either the clearing manager or a retailer trading on the distribution network in which the station is embedded. If the retailer to which the embedded generator sells is not the retailer that is responsible for all the unaccounted for volumes on the network, it must contemporaneously on-sell the electricity to the clearing manager. In other words, an incumbent generator must sell (directly or indirectly) to the clearing manager or the incumbent retailer of the network.

Furthermore, a generator that purchases electricity at the same point of connection with a local network at which it sells electricity must purchase the electricity from the same participant it sold its electricity to. As a result, embedded generators must either purchase and sell all their electricity from the clearing manager (directly or indirectly) or the incumbent retailer. Industrial companies with on-site generators often fall into this category. Under the voluntary NZEM, generators had an option as to whether they participated in the wholesale market by making offers.

2.3.2 Fuel types

There is a mixture of hydro, thermal (predominantly gas and coal, but also some fuel oil), geothermal, wind and biogas stations capacity and generation. Wind generation has featured prominently in the most recent additions to the generation base and in proposed additions. In terms of energy source in 2006, hydro contributed around 56 per cent, gas and coal around 34 per cent and geothermal seven per cent. Co-generation plants accounted for around four per cent. The generating capacities of the major generators differ by fuel type and geographical location.

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15 These requirements will change when the new rules relating to reconciliation come into force on 1 May 2008 as one of the changes is the removal of incumbency obligations on retailers.

Figure 1 Generation capacity by fuel type 2006

MW

Meridian Energy
Contact Energy
Genesis Energy
Mighty River Power
Trustpower
Other

Source: Electricity Commission

Figure 2 Generation capacity by North Island/South Island 2006

MW

Meridian Energy
Contact Energy
Genesis Energy
Mighty River Power
Trustpower
Other

Source: Electricity Commission
Total installed capacity is approximately 8,400 MW, giving total potential output of approximately 73.6 TWh if all plants ran 24 hours a day all year. Current consumption is approximately 40 TWh per year. Installed capacity at a 100 per cent load factor is capable of generating nearly twice the level of consumption. Not all installed capacity is able or designed to be utilised to anywhere near its maximum potential, however, for several reasons:

- fuel constraints;
- transmission constraints;
- resource consent constraints;
- diurnal and seasonal consumption patterns, necessitating the capacity to meet maximum demand; and
- plant maintenance requirements.

a) Fuel constraints

Hydro storage

The principal fuel constraint impacting capacity is water availability for hydro generation. New Zealand has a steep topography making the construction of dams with large water storage capacity costly. New Zealand’s precipitation has relatively strong seasonal differences with most occurring in the spring or winter months. Moreover, there is a noticeable variability and unpredictability of exactly when precipitation will occur and significant changes in overall levels from year-to-year depending on the phase of the southern oscillation in global weather patterns. Consumption peaks in winter when domestic demand is at its highest although in dry weather consumption for irrigation purposes increases in some regions. There is also an increasing tendency for air conditioning to be installed, especially in Auckland, and this is boosting summer peak demand levels.

The results are that New Zealand’s overall water storage:

- averages around the equivalent of 2.5 to 3 TWh or less than 10 per cent of annual consumption of electricity;
- varies over the course of a year; on average, storage is highest in autumn and lowest at the end of winter before the spring thaw in the South Island fills the southern lakes; and
- varies significantly between years.

In dry years, the result can be shortages of effective generating capacity during winter, which is also the period of peak demand. When water storage becomes low, it tends to remain low for several months and generally only fully recovers following the spring thaw,
which can also be variable in terms of the month of the year at which it arrives and peaks.

**Figure 3 Annual hydrology conditions**

In the medium term, gas supply also represents a potential constraint on generating and the uncertainty about gas has certainly been a constraint on parties committing to constructing additional gas-fired generation plant. A large part of New Zealand’s gas supply still comes from the Maui field, making gas-fired electricity generating capacity vulnerable to failures in this facility. The ability to pack additional gas into the pipeline over its full length can provide some cover for planned outages of this facility, but even this capacity is limited. There are no general gas storage facilities in the country.

**Gas**

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Coal

New Zealand has no shortage of coal suitable for use in power generation and also has ready access to imported coal from Australia and Indonesia. New Zealand has, however, ratified the Kyoto Protocol on climate change. How New Zealand intends to meet its obligations under this treaty and in the period beyond 2012 is currently unclear. Signals from the current government indicate it does not favour coal as the fuel for any significant increases in generating capacity.

Wind

Wind generation is a technology in which fuel constraints reduce the achievable load factor well below 100 per cent. With current wind turbine technology the minimum speed of the wind required to generate electricity is 14 to 22 km/hour. The output generated then rises as the wind speed rises until the wind speed reaches about 55 km/hour. At this point, output is maximised. Output remains at its maximum generating capacity until the wind reaches about 90 km/hour, or a bit above for some turbines, when output ceases as the speed has exceeded the high wind cut-out safety limit. Wind turbines
only generate power when the wind speed is within a band and only generate maximum output in a smaller range within the band\textsuperscript{17}. Thus, the total installed wind generating capacity cannot all be used all the time. The load factors – ratios of actual output in MW to the total rated output in MW – of wind generators in favourable sites in New Zealand are in the 30 to 45 per cent range.

These load factors are high by international standards, and the potential for wind generation in New Zealand appears reasonably large, if only technical and operational issues are considered. A study of only technical and operational, and not economic, considerations suggested the potential for wind generation to be about 35 per cent of New Zealand’s installed capacity and about 20 per cent of actual generation\textsuperscript{18}.

\textbf{b) Transmission constraints}

Two yardsticks against which the transmission grid can be judged are whether it is able to satisfy demand, whilst the appropriate grid reliability standard is complied with, given the pattern of generating capacity available; and whether it is able to satisfy demand and grid reliability standards using the lowest cost generation options. The difference between the yardsticks is that the first has only a technical objective but the second requires both a technical and an economic objective to be fulfilled. The second yardstick requires the grid to be capable of allowing the choice of which generator to schedule to be made strictly according to merit order based on offers without taking account of physical transmission constraints in the grid.

The Commission has released an Initial Statement of Opportunities. This applied the first yardstick using projected demand over the next 50 years and five alternative generation scenarios. It found that the grid is currently able to meet the criterion, but, in order for it to continue to meet projected demand and to conform to the Grid Reliability Standard, further investment in the grid, or in alternative arrangements, will be required over time.

Although the current grid meets the technical criterion, it does not always meet the economic criterion. From time to time at peak demand periods there are transmission constraints in the economic sense that impact on prices in the top of the South Island, in the central North Island and into Auckland. Occasionally, the HVDC link between the two islands also acts as an economic constraint. Whether the benefits from removing these constraints exceed the

\textsuperscript{17} Energy Link and MWH New Zealand (2005), p.10.

\textsuperscript{18} Energy Link and MWH New Zealand (2005), p.6.
costs of doing so are matters that Transpower as grid owner needs to establish.

c) Resource consent constraints

A resource consent constraint often reported in the media that impacts on generating capacity is the limit on the water temperature in the Waikato River on output from the Huntly power station. The station discharges warm water into the river raising its temperature and in summer months on hot days the water temperature in the river can come close to, or exceed, the limit necessitating a reduction in output from the station.

Hydro stations are commonly subject to requirements on minimum flows downstream from them. Some significant hydro storage lakes are subject to minimum and/or maximum water levels. For example, Lake Taupo, which has a very important water storage role for hydro generation in the North Island, must have its level reduced leading into winter so that there is sufficient capacity to accommodate high inflows which can occur during winter without causing flooding of the township adjoining the lake. Changes in such flow requirements could materially lower the effective utilisation of hydro stations.

Geothermal stations are subject to restrictions on maximum draw-off rates. Smaller standby generators in main business areas can be subject to constraints on the hours and circumstances in which they can be operated.

d) Diurnal and seasonal consumption patterns and maintenance

A load factor across all generating capacity could only approach 100 per cent if there were no fluctuations in demand and usage over the course of a day or between days. In practice, demand does vary significantly depending on the time of day, the day of the week and the season of the year. Generating capacity is needed to cater for the highest levels of usage. This inevitably means some plant will have less than 100 per cent load factors and some that are used mainly during the peaks may actually have quite low load factors.

Similarly, to achieve 100 per cent plant utilisation requires that the plant never be out of service for maintenance purposes. In practice, this is not possible for any type of plant.

e) Summary

Although New Zealand’s installed capacity is “theoretically” capable of generating about twice the level of electricity consumption if it was all run with a load factor of 100 per cent, the system cannot run with
all plant having a load factor of 100 per cent, and is not designed on the assumption it can. Consideration of the current situation and experience in operating the system suggests, however, that New Zealand:

- currently has adequate generating capacity in most years to physically meet electricity demand but can be short of capacity in dry years because of a shortage of fuel; these dry year constraints, when they occur, can last, with varying degrees of intensity, for several months;
- currently has some grid constraints, which impact on prices in some regions at peak times from time to time;
- faces uncertainty over the availability of gas for electricity generation in the medium term;
- will face increasing fuel constraints as demand increases over time unless there are major gas discoveries soon or increased investment in generating capacity dependent on other fuels; and
- will face increasing economic transmission constraints as demand increases over time, unless there are investments in transmission upgrades or transmission alternatives.

2.3.3 Offering strategies

As noted above, New Zealand generators are not obliged to make offers to generate to the system operator, and they are free to offer at any non-negative price. There is no price cap on offers or on the market price. Moreover, the system operator is not entitled to dispatch a generator that has not offered and the modelling system that identifies the dispatch instructions will not schedule a generator at a price below its offer price.

The Commission is responsible for the offer strategies of the 155 MW Whirinaki reserve energy plant. The current instructions \(^{19}\) from the Commission to Contact Energy, which manages the plant, is that there is to be a standing offer in the market for available plant at $1,000/MWh. Moreover, when the average of the half hourly dispatch prices for the next four hours at the Whirinaki node exceeds the higher of $200/MWh or the variable costs of the plant (the reserve energy trigger price, RETP), output from Whirinaki is to be offered for the first trading period outside the “two hour window” at the RETP. For the purpose of calculating the average of the eight half hour dispatch prices, the dispatch price in each individual half hour is capped at $500/MWh. This is to ensure that a transitory price spike

\(^{19}\) See www.electricitycommission.govt.nz/pdfs/opdev/secsupply/pdfssecurity/whirinaki-offer-strat.pdf
does not initiate Whirinaki offers at the RETP. When water storage is at or below the so-called minzone level\(^{20}\) the standing Whirinaki offer is to be lowered to the RETP. When it is below minzone, the Commission will monitor the dispatch of Whirinaki and, if the station is not making the assumed contribution to security, the offer price may be reduced if the Commission determines that a lower offer price will assist in achieving the one in 60 years policy objective. If storage increases from below to above the minzone level the output at Whirinaki will be offered at the RETP until storage increases to a level 25 GWh of more above the minzone. If Whirinaki is fuel constrained in an extended event, it will be offered at the RETP for periods where the Commission expects it to provide the greatest benefit to security and at $1,000/MWh at other times.

2.3.4 Investment in generation

Investment in generation has, since the early 1990s, been left largely to the market. The only current exceptions are the Whirinaki reserve energy plant and the government accepting the gas supply risk for a new plant at Huntly, eP3. In the GPS, however, the Commission is instructed to contract for reserve energy to deal with a one in 60 years dry year and “to help cope with other unexpected supply contingencies, such as serious grid, plant or fuel supply disruption”\(^{21}\). The Commission is further instructed that its portfolio of reserve energy should be limited so that it is capable of producing no more than 1,200 GWh of reserve energy over any given four month period. There are 2,920 hours in four months, so this appears to limit the Commission to 0.411 GW or 411 MW of capacity compared with its current 155 MW at Whirinaki (although if it is assumed that reserve energy will not be produced 24 hours a day, which is likely to be the case, the capacity limit could be effectively significantly higher than 411 MW).

Although investment has been left largely to the market for over 10 years, there has been no shortage of projects put forward and discussed. In a study NZIER undertook for a client, it identified over 6,000 MW of generating plant that had been suggested by various parties. Only 25 per cent of this is judged to be economic, given likely plant costs and forecast prices, but this still exceeds 1,500 MW. More importantly, new plant has come on stream in time to cater for increased demand.

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\(^{20}\) The minzone is the level of aggregate water storage in hydro lakes necessary to ensure that given demand forecasts and assuming the availability of non-hydro storage generators emergency demand constraint measures will not be necessary in the event of a one in 60 years dry year.

\(^{21}\) New Zealand Government (2004), para 47.
2.3.5 Long-run marginal cost of generation

In 2003, the Ministry of Economic Development (MED) published its estimates of the long-run marginal cost of electricity generation in New Zealand for various types of generator\(^{22}\). Its estimates, inclusive of carbon charges, in c/kWh were: geothermal (4.0 to 8.5); co-generation (4.6); gas combined cycle (5.7 to 8.5); wind (6.2 to 8.5); hydro (7.0 to 8.5); South Island coal (7.6 to 8.6); LNG (8.5 to 11.6); North Island coal (9.8 to 10.9); fuel oil (11.3 to 12.0); distillate (16 to 17). For the lower cost options the potential volumes identifies by MED were modest. Since MED made these estimates, the international prices of hydrocarbons have increased substantially and this will have impacted on the costs of electricity from these fuels.

2.4 Purchasers

The purchaser market participants in the wholesale spot market fall into two main groups:

- Retailers, which purchase electricity from the clearing manager and supply electricity to a consumer or to another retailer; and

- direct consumers, which purchase electricity from the clearing manager for their own consumption at either a point of connection to a local network, but more usually at a point of connection to the grid.

Generators can also become purchasers, at least temporarily, when they experience plant outages.

2.4.1 Retailers

The significant members of the first group are the same firms as the major generators – Meridian Energy, Genesis Power, Mighty River Power, Contact Energy, Trustpower and Todd Energy. In addition, there is King Country Energy which has several small power stations in the central North Island and a retail client base located largely in the same area\(^{23}\).

The New Zealand market is vertically integrated with each of the major generators being a retailer and each retailer being a major generator. The significance of the degree of vertical integration for the level of competition in the retail market and the development of an active and transparent forward market has been a matter of considerable debate.

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\(^{23}\) In late 2006, Todd Energy made a take-over offer for 100 per cent of the shares in King Country Energy.
The energy balances of the vertically integrated generator-retailers differ significantly from one another, as do their mix of generators and hence their vulnerability to dry year risk impacting hydro generating capacity.

Figure 5 Energy balance of major vertically integrated generator/retailers 2003

2.4.2 Direct consumers

The second group – direct consumers – are generally major industrial firms. Some of them operate co-generation plants. Apart from their own generation, these firms tend to buy the majority, or all, of their electricity from the market, sometimes with the use of an agent. Some choose also to purchase from retailers separate financial arrangements to cover their exposure to movements in the spot price incurred when buying on the wholesale market.

2.4.3 Demand characteristics

The country’s small population means that the amount of electricity consumed in industrial facilities can significantly influence overall demand patterns. The industrial sector consumes approximately 44 per cent of electricity, the commercial sector 22 per cent and the residential sector 35 per cent.\(^{24}\)

New Zealand’s major demand centres are the main cities, particularly Auckland, and isolated large-scale industrial facilities – an aluminium smelter, wood processing plants, dairy factories and a steel mill. Rio Tinto New Zealand at Tiwai Point near Bluff consumes approximately 15 per cent of New Zealand’s total electricity smelting aluminium. Dairy factories have highly seasonal demand patterns with the largest use in the spring when the grass is growing most vigorously and milk production is highest. Use diminishes during summer and autumn and is lowest in winter when milk production, except for the fresh milk market, ceases. Fresh milk processing requires relatively little energy.

Climate and weather also have a major influence on the demand for electricity. The peak load comes in winter when electricity is particularly in demand from home heating and clothes drying. A cold front moving up the country can have a dramatic impact on household demand and demand overall. The speed and temperature impact of cold fronts is relatively hard to predict. Residential use also dictates the pattern of use during the day. The peak periods of consumption are the early evening and the morning. The lightest demand period is in the early hours of the morning.
Figure 6 Weekly demand comparison

Weekly National Demand 2004 - 2006
(Last updated 13 December 06, for week beginning 06 December 06)

Note: Based on unreconciled gwh metering information that is subject to change

Source: M-co (2006b)

2.5 Wholesale market outcomes

2.5.1 Spot prices

The wholesale spot market produces electricity prices for each of approximately 250 nodes on the grid for each half hour. These nodal prices reflect both transmission constraints and transmission losses as well as the cost of electricity.

The following charts show the Electricity Price Index over the period 2000 to 2007. The EPI is a seven-day rolling average electricity price and so smooths out the effects of weekend drops and short-term price spikes caused by temporary line and generating plant outages. The prices at the nodes in the three regions are weighted by demand (MW load). This gives more significance to prices in peak use periods and at grid exit points where most of the electricity is taken off the grid.
Figure 7 Electricity price index

Index (c/kWh)

Total New Zealand

Regions – Upper North, Lower North and South

Source: M-co
Two features of these charts are worth noting:

- the impacts of the dry years in 2001, 2003 and concerns about precipitation and supply generally in 2006 on overall price levels are very noticeable; and
- the prices in the three regions do not separate noticeably in the high price periods associated with dry seasons; at most times other than those associated with dry years, the index prices have usually averaged around 5c/kWh or $50/MWh.

The last point is significant in that 5c/kWh or $50/MWh is below the level of the average generating costs of new gas-fired plant, given the current price of gas at $7 to $8/GJ, and expected costs likely to be associated with carbon emissions even if an emissions trading approach is adopted in place of the previous proposals to have a carbon tax. It is also low relative to the estimates of the long-run marginal cost of generation for virtually all potential new plant according to Ministry of Economic Development (2003) and costs for hydrocarbon fuels have increased sharply since then. In other words, the price of electricity has generally been below the costs of adding to the capacity to produce electricity except in dry years and in 2006 when concerns increased about the need for additional generating capacity.

In the wholesale electricity market, a different spot price is calculated for each of approximately 250 nodes. The following charts show monthly average spot prices at some key nodes and variances between the spot prices at selected nodes. They highlight that monthly average spot prices do vary significantly between various nodes.

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Figure 8 Monthly average spot prices
$/MWh

Haywards, Gisborne and Otahuhu nodes

Benmore, Stoke, and Invercargill nodes

Source: M-co
Figure 9 Differences in monthly average spot prices
$/MWh

Gisborne - Haywards and Otahuhu - Haywards

Invercargill - Benmore and Stoke - Benmore

Source: M-co
2.5.2 Instantaneous reserves

The wholesale spot market for electricity in New Zealand not only determines the price of electricity at each node and the generators that will run to provide electricity, but it also determines which parties will provide instantaneous reserves and the prices they will be paid. Instantaneous reserves can be provided by generators or by interruptible load. The following charts show the quantity of reserves by source and the cost of reserves by source. A noticeable feature is the significance of interruptible demand as a source of instantaneous reserves.

Instantaneous reserve prices naturally impact on the payments to providers. The costs of these payments are allocated in two parts – availability costs and event charges. The availability costs are allocated to generators and the HVDC owner on the basis of the injections net of instantaneous reserves that they provided. The calculations are done separately for the North and South Islands and for each trading period. For the HVDC, the injection is calculated based on which island the flow is into and the level of the so-called “at risk HVDC transfer”. The upshot is that the availability costs are allocated according to the amount of electricity provided. When prices are very low, this can have a negative effect on parties willingness to offer into the market.

Figure 10 Cost of reserve by source (2003 vs 2002)

The event charge is payable by the causer of an under frequency event and is based on the estimated average availability cost per unit of electricity lost per event. Any event charge that is paid is rebated to those that paid the availability costs during the month in which the event occurred and the two preceding months. The purpose of this arrangement is that if there are no events, the availability cost payments would cover the costs of availability, but if there are events, those that cause them pick up the costs.

The event charge can have the effect of making parties that have generating plant (or the HVDC link) that they know may be vulnerable to breaking down and causing under frequency events to be reluctant to offer their plant, or to do so at a higher price to offset the risk.

### 2.5.3 HVDC flows

The spot market also determines the volume of electricity that will flow across the HVDC link between the two islands and also the direction of the flow. The usual direction is from south to north but reverse flows occur from time to time especially in winter when South Island demand is high because of the cold weather and South Island lakes are depleted due to heavy generation earlier in the year and lack of water inflow because the precipitation stays on the mountains as snow. Southward flows are far more significant in dry years than
in normal or wet years and have been more significant in 2005 and 2006 than previously.

When the HVDC link is operating at the maximum capacity available, the wholesale electricity markets in the two islands become effectively separated from one another and the prices in the two islands can diverge quite sharply.

Figure 12 HVDC transfers
Average kW transfer per ½ hour

Source: Electricity Commission

3. The retail market for electricity

Only a very small number of industrial and commercial businesses buy electricity directly from the clearing manager through the wholesale spot market, and several of these still buy much of their electricity from a retailer or generate the electricity themselves through a co-generation plant. Most electricity consumed in New Zealand is bought under a bilateral contract between the consumer and a retailer. As the retailers are also generators, this means that most electricity is bought under bilateral contracts between a consumer and a generator.
3.1 Households

The contracts retailers offer households vary depending on the line company that serves the customer. This is because most retailer contracts combine the line and energy charges into one service and therefore the pricing and price structure of the service depends in part on the pricing and price structure of the line company, which vary across the country. Auckland is the principal area where the two services are provided separately, although even there householders receive a combined bill for both services from the retailer.

Retailers generally offer a variety of plans to households. Virtually all contain a fixed daily rate and a charge depending on energy usage. Government policy and regulations require that households be offered a low fixed charge option. The policy intention is to encourage energy conservation by households. Some plans allow the water heating to be turned on and off by ripple control transmitted down distribution lines, others do not. In some areas, plans with prices that vary depending on the season are offered. This is usual only in areas where the line company offers a seasonal differential charging structure to retailers.

In some areas, differential day and night rate options are offered with the night rate only available for some appliances, like night-store heaters and hot water cylinders. More complex time of use charging is not offered to householders. Nor are contracts with long-term fixed prices. The usual terms of the contracts with households allow charges to be changed by the retailer giving notice to the consumer. In some contracts the notice is able to be given by advertisement in the newspaper instead of directly.

Charges for household consumers do not vary as a matter of practice, or contract, in step with movements in the wholesale spot price. Prices for consumers are not automatically pushed up in dry years and lowered in wet years. Some retailers have, however, experimented with incentive schemes to encourage reductions in household energy usage in dry years. Under one contract, the retailer is entitled to change the pricing plan and other terms of the agreement with only 48 hours notice “Under extreme circumstances where energy supply is limited … or where any threat to our ability to supply energy exists…”26. As that retailer is a significant net generator, and is likely to remain so even in a very dry year, the circumstances when it would be justified in exercising this right if challenged are not very likely.

26 Contact Energy (2002), p.3.
Even though the terms of the contracts for households provide that the prices can be varied unilaterally and with short notice, from a price risk management perspective they have the characteristics to the retailer of fixed price contracts. If wholesale spot prices should rise sharply due to a dry year effect, the prices under these contracts will not rise much, if at all. If one retailer decided unilaterally to raise prices, any retailer that is still a net generator, or has the resources to sustain what is a seasonal impact, could use this opportunity to “cherry-pick” their client base. The retailer contemplating this would balance the short-term cost of supplying the newly acquired retail clients at a loss during the seasonal shortage against the longer-term gains from increasing market share. The general inertia of households in changing supplier will tend to improve the prospect of long-term gains.

As these household contracts are effectively similar to long-term “fixed price” contracts for the retailer, they are effectively “fixed price” contracts for household consumers also, even though a straightforward reading of the terms of the contract would suggest otherwise. Households appear to understand this. They do not expect their charges will fall in wet years and in turn they do not expect they will rise in dry years.

3.2 Small businesses

The contracts that retailers offer to small businesses are the same or very similar to those offered to households and therefore do not require separate discussion.

3.3 Larger businesses

A study of the websites of the retailers suggests a very broad range of options as regards managing price risk exposure is available to larger businesses whether they are in the commercial or industrial sphere. Based on website analysis, larger businesses can:

- buy their electricity on the basis of the spot price, provided they have an appropriate meter;
- buy their electricity on the basis of a fixed price/fixed volume contract for a negotiated term; in some instances the fixed prices and volumes vary monthly or seasonally and can also vary with

27 The phenomenon of short-term legal contracts giving rise to quasi long-term fixed price obligations is not unique to this market. It is also found in financial markets. The examples there are low and non-interest bearing cheque and savings accounts. These funds are usually at call – so the legal arrangement is short term, but the rates do not vary much as wholesale spot interest rates vary and neither do the balances.
time of use during the day and week; any volume above the maximum is charged for at some average of spot prices;

- buy their electricity on the basis of a fixed price/variable volume contract for a negotiated term; the fixed prices usually vary monthly or seasonally and can also vary with time of use during the day and week;

- buy financial swap contracts for either fixed volumes or sculptured volumes; these are settled in cash monthly; and

- subscribe to e-mail alert services that tell them when the wholesale spot price of electricity is expected to exceed a range of trigger levels.

In addition, of course, access to the wholesale spot market for electricity is open to every party willing to be subject to the rules applying to purchasers, including the fees and levies. The “costs” of direct access include:

- the standard levy, which also covers access to COMIT, the market electronic information system;

- the costs of providing bids for each half hour, although this can be contracted out; and

- the costs of supplying prudential security to the clearing manager if the firm’s long-term credit rating is below Standard & Poor’s A- or the equivalent from another rating agency.

Purchases on the wholesale market are at the spot price and, unless a direct purchaser is willing to accept the price risks, the direct purchaser also has to incur the search and transaction costs to acquire and monitor financial hedge contracts to manage this risk.

The interactions between parties participating in both the retail and wholesale markets are presented in the chart. It outlines the parties involved, and the flows in the electricity market – in terms of the flow of electricity and the flow of money, as well as the process flows involved in the sale and purchase of electricity.
Figure 13 Flows in the electricity market – electricity, money and processes

Consumers - supplied via lines companies (e.g. domestic users, most commercial and light industrial users)

Lines Companies (28 companies)

Retailers (Generator/Retailers plus Trustpower are major retailers)

Generators (excl. on-site cogen) (Mighty River Power, Genesis Power, Meridian Power, Contact Energy, some independent generators)

Grid owner (Transpower)

System operator (Transpower)

Power system security management

Ancillary services management

Energy scheduling and dispatch (day ahead and real-time)

Wholesale Spot Market “pool”

M-Co - COMIT

Financial Markets

Generators - retail aggregates customer use data

Motor - generator production information collates

National Reconciliation Manager (d-Cypha - subsidiary of Transpower) - collates metering information (volumes) of electricity bought and sold and data from Grid Operator (Transpower)

Pricing manager (MCo) - runs SPD model to determine price

Clearing Manager (MCo) - collates final price and volume information and identifies amounts owed for NZEM sales and for non-market sales

Source: NZIER

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4. The forward or hedge markets for electricity

Judging from the publications of retailers, the consumers of significant quantities of electricity have available to them longer-term contracts for electricity offering a range of price risk characteristics from complete exposure to the spot market to no exposure at all for the term of the contract. Most businesses that do not consume significant quantities of electricity and households have less choice, and effectively buy electricity on a fixed price basis from a risk management perspective even though the legal contracts they have may suggest otherwise.

If the advertisements and publications of the retailers are taken at face value, it appears that all sectors of the market either have fixed price or hedge contracts (whether they want them or not in the case of consumers of smaller quantities) or have access to a range of hedge products through retailers. In view of this, claims that the hedge market in New Zealand is under-developed need some explanation.

The claims appear to be that:

- there is no active market for term contracts for electricity;
- the prices for term contracts are not transparent;
- the prices for term contracts are not reasonable;
- the hedge products are not always available when purchasers want them, in the form and volume they want; and
- the terms and conditions of the contracts that are available are dictated by the generator-retailers and the terms unduly favour them, particularly in relation to force majeure and suspension clauses.

The first point is undoubtedly correct. There is a web-based “EnergyHedge” market, but at present only large generators are participants because of the credit risk requirements and the level of trading is not high enough to suggest the market is an active one.

On the second point, there is the fixed price index which is published monthly and provides an indication of the fixed price contracts struck between the retailers that participate in the index and other

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29 www.energyhedge.co.nz/ePublic/mtrade.mt_public.home
30 M-co (2005c).

NZIER – The markets for electricity in New Zealand 46
parties. It provides separate data on deals for one, two and three years and is divided into deals in the Upper North Island, Lower North Island and South Island. Although this index provides at least some information, unless the data provided are based on reasonably standard contracts, it may be misleading. Even if the index is statistically robust, its publication is well short of making the market transparent. The “EnergyHedge” market also provides some insight into the forward price curve, but the narrow range of participants and the volumes involved undermine the level of transparency it creates.

On whether the hedge prices are reasonable, there are conflicting claims\(^\text{31}\). This is unsurprising and not just because buyers and sellers must disagree about value or there would be no trading at all. Both the buyer and seller in a New Zealand term contract for three years, for example, do not know how many, if any, dry year events there will be in that time and how severe they will be in terms of impact on price. Buyers will tend to believe that the premium to cover this risk is too great and sellers will tend to believe the opposite.

On the last point, a study of contracts for the Major Electricity Users Group by NZIER found that:

> The force majeure and suspension clauses that are included in some New Zealand electricity hedges … allow sellers to default if their own power stations are not generating or cannot be dispatched. Default is not unavoidable in these circumstances and hence these cannot be considered FM [force majeure] events\(^\text{32}\).

A study of the state of competition and entry barriers to New Zealand’s wholesale and retail electricity markets noted:

> Potential retailers and potential IPPs [independent power producers] are unable to secure their business or even value their business without an active forward market. Any determined entrant also faces having to buy forward or sell forward with a competitor. These circumstances inhibit retail competition and investment in generation. During the structured interviews the lack of a vibrant source of hedge contracts arose often and was repeatedly cited as one of five main barriers to investment or entry\(^\text{33}\).

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\(^{31}\) LECG and TWSL (2005b), pp.16-17.

\(^{32}\) NZIER (2005d), p.i.

\(^{33}\) LECG and TWSL (2004), p.34.
5. The markets for ancillary services

5.1 Types of ancillary services

The system operator must keep consumption (including losses) and injections in the system in balance, and so keep the system within the permitted frequency range, keep the voltage at the right level, and restart the system when it suffers a complete collapse. The system operator carries out these functions by purchasing what are called ancillary services. The various kinds of ancillary services are:

- fast instantaneous reserves;
- sustained instantaneous reserves;
- over frequency reserves;
- voltage support; and
- black start.

5.2 Reserves

Any imbalance between supply and demand causes the system frequency on an AC grid to deviate from the standard. In New Zealand, the standard is 50 Hz. If frequency moves too far from the standard in either direction, damage can occur to generators and some kinds of loads. It is important that any change in frequency is quickly corrected. Frequency management occurs at three levels.

5.2.1 Regulation or frequency keeping

In each of the North and South Islands, one generating station is designated in each half hour as the “frequency regulating station”. It constantly regulates its output at a rapid rate to maintain the frequency within the limits of 49.8 Hz and 50.2 Hz. There is a different station in each island because the frequencies in them do not need to be the same. The two islands are connected by a HVDC link, but frequency is not a component of DC power.

5.2.2 Instantaneous reserves

Large, rapid and potentially damaging drops in frequency can occur when a large amount of generation is suddenly lost to the system through a generating station malfunctioning or a fault in the transmission grid. To deal with such situations, the system operator has available instantaneous reserves. In New Zealand, these take two forms: fast instantaneous reserves, which have to be available six seconds after the event if generation and within one second of frequency falling to 49.2 Hz if interruptible load, and sustained
instantaneous reserves, which have to be available during the first 60 seconds and be able to be sustained for at least 15 minutes.

The former are primarily used to stop the drop in frequency and the latter to return the system to the narrow tolerance band around the 50 Hz standard. There are two sources of reserves: spinning reserves from generating units that are synchronised and spinning at no load or partial load and interruptible load that is automatically tripped by under frequency relays or by manual intervention.

How far frequency falls when generation is lost is dependent on the characteristics of the generators connected and running at the time. For this reason, the EGR impose requirements on the ability of generators connected to the grid to stay connected, or “ride-through” under frequency events without disconnecting themselves and adding to the difficulties of restoring frequency. The requirements are different in the two islands. This is because they have been calculated based on the dynamic performance of the grid in each island and these differ.

5.2.3 Over frequency reserves

A large increase in frequency in the South Island could also come about if the HVDC link disconnected whilst sending significant energy northwards. For this reason, some generators in the South Island have specially fitted relays which activate and disconnect the generator to prevent frequency rising to excessive levels.

5.3 Voltage support

Generators produce and consumers use both real and reactive power. Real power is the normal electricity used to run lights and heaters, etc. Real power flows from generators to load, but reactive power flows back and forth with no net transfer of power in either direction and supplies no energy. Despite this, however, a supply of reactive power is useful in helping to overcome the problems caused by real power. It helps keep the voltage at the load end of a line at its proper level. Moreover, the thermal limit on real power flow depends on the amount of reactive power flowing at the same time, although the relationship is not very strong. Reactive power is only a feature of AC systems and has no counterpart in DC flows. The unit of measurement for reactive power is “kVAr” which stands for “kiloVolt-Amps reactive”.

Loads and transmission tend to use more reactive power than they produce. When too much reactive power is taken out of the system, the voltage sags. It is usual for the system operator to devote some
system resources to producing reactive power to support voltage. When reactive power is transmitted it increases the loss of real power and reactive power is also lost. Because the losses of reactive power are reasonably high, it cannot be transmitted over long distances. This means most reactive power needs to be produced locally. There are three common sources:

- capacitors attached to power lines;
- synchronous condensers; and
- synchronous generators (generators that have average rotational speed exactly proportional to the system frequency).

5.4 Black start

Some generators require electricity from the grid in order to start themselves. As a result, if the system goes down they cannot help restart it. Power stations that provide black start capability are fitted with stand-by generators which can self-start and therefore can be used to re-energize the grid. Some types of generators, such as hydro stations and wind generators, are more readily started with minimal or no power and are therefore cheaper sources of black start capacity than others, such as those that require power to pump fuel.

5.5 Purchase of ancillary services

In New Zealand, Transpower as system operator buys all ancillary services through contestable processes among providers and passes the costs on to its customers\(^34\). The supply sides of the markets are therefore competitive and the demand sides have a single buyer, the system operator. With the exception of voltage support through the purchase of reactive power, ancillary services have strong public or club good\(^35\) characteristics and, in the absence of mandatory purchase by the system operator, there would be significant free-rider problems as grid users would be able to enjoy the benefits of the services even if they did not contribute to paying for them because excluding them access to the benefits would be practically impossible.

Instantaneous reserves are bought from generators and providers of interruptible load through the wholesale spot market. There is a

\(^34\) For a description by Transpower of the purchaser of ancillary services, see Transpower New Zealand (2004c), pp.19-23.

\(^35\) The economist’s definition of a public good is that one party consuming or using the good does not preclude another party from doing so (non-rivalrous in consumption) and it is practically impossible to exclude a party unwilling to pay from consuming it (non-excludable). Defence services are a common example. Club goods are also non-rivalrous, but excluding users who do not pay is practicable. A golf course is an example.
requirement on parties wishing to offer instantaneous reserves to register with the system operator, but the criteria for registration are technical in nature. The system operator determines the security requirements that are used by the dispatch process to determine the quantity of instantaneous reserves to be scheduled for each half hour trading period, but does this within the guidelines set by the Part C of the rules, which deal with common quality. The price of the instantaneous reserves was determined by an open competitive half hour clearing market that is optimised with the energy market as required in the dispatch objective function.

Frequency keeping services are bought by the system operator using annual contracts let through an open tender process. Qualified generators in each island are invited to bid. The qualification criteria are technical and are aimed at ensuring the offered plant has the physical capability to provide frequency keeping reserves.

Voltage support services are purchased by the system operator:

- through medium-term contracts with asset owners to provide voltage support services at key locations on the grid let by competitive tender;
- through the purchase of power through the wholesale spot market; and
- when the other two sources have been exhausted, by constraining on generation capable of meeting the requirements of voltage support at the lowest cost.

Black start services are purchased by the system operator through an annual competitive tender among generators with units capable of providing the service.

The over frequency reserves service is purchased by the system operator from generators with generating plant in the South Island equipped with over frequency relays for tripping using competitive tenders.

It is technically possible to identify who creates and who uses reactive power, which has led to suggestions that there should be a market for reactive power similar to the market for real power, with the price of reactive power set to clear the market.

The costs of transmitting reactive power are relatively high; losses in transmitting it are roughly 10 times greater than losses in transmitting real power. Any market for reactive power in New Zealand is likely to face severe competition issues due to the costs of transmission limiting the number of potential providers in an area. Combined with the costs of identifying the consumers and producers of reactive
power, and that the system operator spends only approximately $2 million per year on this ancillary service, this means it is very unlikely that a net market benefit would flow from establishing such a market in New Zealand.

### 5.6 Payment for ancillary services

Whilst the system operator purchases ancillary services, the EGR set out in Part C how the costs of their provision will be allocated. The rules provide that:

- frequency keeping costs are allocated to purchasers based on proportion of volume purchased by them;
- instantaneous reserve costs are allocated in two parts:
  - availability costs are allocated to generators and the HVDC owner based on injections; and
  - event charges are allocated to the causer of the event;
  - event charges actually collected are rebated to those that paid the availability costs in the month of the event and the preceding two months;
- over frequency reserve costs are allocated to the HVDC owner;
- voltage support charges are allocated in three parts on a zonal basis:
  - a nominated peak kVAR charge allocated to each distributor and each generator with a dispensation from the reactive power capability required for its generator under the rules;
  - a monthly peak penalty charge allocated to distributors based on how much their kVAR peak usage was above their nominated peak usage in the month; and
  - an annual residual charge or payment allocated to distributors and generators with dispensations so as to ensure the actual costs of providing reactive power are fully recovered;
- black start costs are allocated to the grid owner.

### 6. The markets for other electricity market related services

A range of other services are required to operate the markets for electricity in New Zealand. These are provided by a range of service

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providers under contract to the Commission. The service providers and their responsibilities are as follows.

6.1 System operator

Responsible for scheduling and dispatching electricity in a manner that avoids fluctuations in frequency or disruption to supply. Responsible for acquiring and utilising ancillary services.

6.2 Market administrator

Provides a number of operational and administrative services to the market under Parts D (Metering Arrangements), E (Registry Information and Customer Switching), G (Trading Arrangements), H (Clearing and Settlement) and J (Reconciliation) of the rules.

6.3 Pricing manager

Responsible for calculating and publishing final prices.

6.4 Clearing manager

Responsible for monitoring prudential security requirements and invoicing and settling electricity and ancillary service payments.

6.5 Reconciliation manager

Facilitates the monthly reconciliation process and is responsible for reconciling metering data against a register of contracts and passing the data to participants and the clearing manager.

6.6 Registry

The database that identifies every point of electricity connection using an ICP reference, enabling energy flows between retailers to be reconciled. The registry also informs retailers when a customer switches supplier.

6.7 Purchase of other services

Apart from a requirement that for a period of five years Transpower would be the system operator, all but one of the other service provider roles are provided under contracts agreed following competitive tendering and negotiations. The exception is the registry contract; there was no competitive tender for this role when responsibility shifted to the Commission. The service provider contracts are evergreen contracts with a rolling notification period
able to be given by either side. There is a contestable supply side, but a single buyer, the Commission.

7. The “market” for transmission asset services

The provision of transmission asset services is largely through administrative rather than market processes under the current rules of the New Zealand market. The Commission plays a very large part under Part F of the rules, which covers the provision and pricing for transmission assets.

7.1 Transmission agreements

Under Part F, Section II, the Commission determines the structure of transmission agreements and which market participants must enter into them with Transpower. Transpower and the designated transmission customers identified by the Commission are required to enter into transmission agreements.

The Commission determines the matters to be included in transmission agreements and determines the contents of benchmark agreements. These provide the basis for Transpower and designated transmission customers to negotiate agreements and act as default agreements if the parties fail to execute an agreement by negotiation.

7.2 Grid upgrades and investments

Under Part F, Section III, the Commission must determine the most appropriate grid reliability standards and the core grid. The Commission also determines the most appropriate grid investment test to apply in developing the grid reliability standards, reviewing and approving investments in the grid, and reviewing transmission alternatives. Transpower is required to use the grid investment test to determine the proposed economic investments for inclusion in the grid upgrade plan.

The Commission is also responsible for preparing statements of opportunity to enable identification of potential opportunities for efficient management of the grid, including investment in upgrades and investment in transmission alternatives. In order to assist in the achievement of this objective, the Commission is required to prepare and publish grid planning assumptions. The Commission is also required to establish and publish a centralised data set giving information on network capabilities, performance and constraints.
Transpower has the role of preparing a grid upgrade plan, but the Commission has responsibility for reviewing and approving the reliability and economic investments proposed in it.

### 7.3 Transmission pricing methodology

The Commission is also responsible for approving the transmission pricing methodology developed and proposed by Transpower. Whilst Transpower develops the methodology, in doing so it is required to follow the process laid down by the Commission and the guidelines the Commission has issued. Moreover, the Commission has the power to make any amendments to the submitted pricing methodology it considers necessary to ensure that the methodology is consistent with the Commerce Commission’s threshold regime under Part 4A of the Commerce Act 1986, the pricing principles laid out in the rules and the guidelines it issued to Transpower.

Transpower is required to apply the transmission pricing methodology approved by the Commission and if it does so its charges are enforceable against designated transmission customers.

### 7.4 Financial transmission rights

The Commission is required to oversee the development of financial transmission rights in accordance with the GPS. The Commission was required to report to the Minister of Energy on progress with this task at such times as the Minister may request.

### 7.5 Role of market based decisions

As can be seen from this description, the role for market based decisions in relation to transmission is very limited. It is possible that the prospects of commercially sponsored transmission alternatives providing superior solutions under the grid investment test may lead the Commission to reject one or more investments proposed in the grid upgrade plan by Transpower. There is, however, currently no mechanism by which such transmission alternatives could obtain funding or be sanctioned to levy charges. There is also the possibility that Transpower and customers may voluntarily agree on higher standards than in the grid reliability standard. In other respects, the decision making process is entirely administrative.

### 7.6 Part 4A of the Commerce Act 1986

Transpower, like other large electricity lines businesses, is subject to the threshold regime administered by the Commerce Commission under Part 4A of the Commerce Act 1986. Currently, this imposes on
Transpower a price path threshold and a quality threshold. If its prices increase by more than CPI minus one per cent in a year, it has breached the threshold and is liable to investigation and potentially to control, if the Commerce Commission so decides. If Transpower breaches the quality threshold, the Commerce Commission can investigate, but is precluded by the legislation from taking any effective action relating to quality\textsuperscript{37}.

The price path threshold currently applies to all Transpower’s transmission related activities, which include its transmission ownership role and system operator activities. The direct costs of it purchasing ancillary services on behalf of the market are not covered, however, because these are purchased in contestable or competitive markets and Transpower merely recovers the costs.

The rules of the electricity market make it clear that Transpower’s prices are subject to this threshold regime even if the pricing methodology to which they relate has been sanctioned by the Commission\textsuperscript{38}. Moreover, the approved costs incurred by Transpower in relation to an approved economic or reliability investment are recoverable by Transpower on the basis of the transmission pricing methodology approved by the Commission. Thus, recovery of the approved costs of approved investments is subject to the price path threshold.

The Commerce Commission is required to take into account “any electricity governance regulation or rule, or decision made under them, that relates to or affects the quality standards or pricing methodologies applicable to Transpower” before exercising any of its powers of control\textsuperscript{39}. It is also required to, “if asked by the Electricity Commission to do so, reconsider an existing authorisation or undertaking”\textsuperscript{40}. These provisions do not, however, require the Commerce Commission to alter its thresholds applying to Transpower because of investments made by Transpower.

Transpower reported in each of its first three disclosure statements under the threshold regime that it had breached its price path threshold. The Commerce Commission investigated these breaches and in late 2005 reached the preliminary view that it should impose control upon Transpower. While consulting with interested parties on whether or not to impose control, Transpower proposed to the Commerce Commission the basis of a settlement agreement as an

\textsuperscript{37} Commerce Act 1986, s.57M (2).

\textsuperscript{38} Electricity Governance Rules, Part F, Section IV, 7.2.1.1.

\textsuperscript{39} Commerce Act 1986, s.57MA (2)(a).

\textsuperscript{40} Commerce Act 1986, s.57MA (3).
alternative to the imposition of control. Since March 2006, the Commerce Commission and Transpower have been engaged in discussions about Transpower’s proposed settlement agreement.

The information disclosure requirements on Transpower that were formerly the responsibility of the Ministry of Economic Development have become the responsibility of the Commerce Commission \(^{41}\).

### 7.7 State-Owned Enterprises Act 1986

Transpower is an SOE under the State-Owned Enterprises Act 1986. As such, it has the principal objective “to operate as a successful business” and to that end be “as profitable and efficient as comparable businesses that are not owned by the Crown” and be “a good employer and an organisation that exhibits a sense of social responsibility by having regard to the interests of the community in which it operates …”\(^ {42}\).

As an SOE, Transpower is also required to prepare a Statement of Corporate Intent (SCI)\(^ {43}\) and Transpower’s Board is accountable to its shareholding Ministers for the performance of the organisation. The SCI forms part of the accountability process, as does the requirement on Transpower to appear before a Parliamentary Select Committee and answer questions. Such a request is usually made by the Select Committee at least once each year. Although the Board of Transpower is obliged to “consider any comments on the draft statement of corporate intent that are made to it … by the shareholding Ministers” there is no obligation on its Board to accept those comments and to amend the SCI\(^ {44}\). In effect, to the extent that the SCI constitutes a further regulatory constraint on Transpower, it is a self-imposed one.

### 8. The “market” for distribution services

#### 8.1 Market structure

There are 28 “large electricity lines businesses” in New Zealand. They range in size from having around 5,000 electrical connections to having nearly 500,000 connections. There are also a number of other entities that provide electricity distribution services as part of their normal activities. Included among these are airports, ports, and

\(^{41}\) Commerce Act 1986, s.57T.

\(^{42}\) State-Owned Enterprises Act 1986, s.4.


large shopping mall operators. For the purposes of analysing the market for distribution services, these can generally be ignored.

The ownership of distribution companies is a mix of publicly listed companies, shareholder trusts, community trusts and local body ownership. Each company tends to have defined geographic areas of activity. Through acquisitions of other distribution companies several now operate in a number of discrete areas. Distribution companies do not have exclusive legal territorial franchises. Their predecessor entities did and were obliged to provide supply to most locations, but these restrictions were removed at the early stages of reforming the electricity market in 1993. Distribution companies still have an obligation to continue to supply existing customers of their predecessor entities until 2013, 20 years after the reform.

The normal Commerce Act provisions apply to mergers of distribution companies. The test is whether the merger will lead to a “significant lessening of competition”. It is hard to argue that the merger of two geographically distinct monopoly distribution companies would lessen competition as there is none; therefore there is little if any constraint on mergers in the sector. As there are economies of scale in the provision of distribution services, the non-commercial nature of much of the ownership probably explains why there have not been more mergers.

### 8.2 Electricity Industry Reform Act 1998

Historically, the distribution companies were also the electricity retailers in each area and this remained the pattern in the early stages of reform. Some distribution businesses also operated generating plant in their region. In July 1998, however, the Electricity Industry Reform Act 1998 was enacted by Parliament. The main provisions of this Act require the separation of ownership and control of electricity retailers and generators from electricity distribution businesses. Businesses were given just on 12 months to achieve this separation and most existing distributors sold their retail activities and generating stations to generators. A handful adopted the opposite strategy and sold their lines businesses and bought generation and additional retail market share.

The policy intent was to curtail the natural monopoly powers of distribution companies and make the generation and retail markets more competitive. To this end, the Act also provided for the split up of the SOE generator ECNZ into three SOEs. From this split Genesis Power, Mighty River Power and Meridian Energy were created. Although it was not the objective of the legislation, one outcome was to establish strong vertical integration between the suppliers of
generation and the suppliers of retail electricity and the withdrawal from the marketplace of a number of independent retailers and energy brokers. Consumers faced less choice as to retail provider as a result of the legislation.

The provisions requiring the separation of distribution from retailing remains in place. There has, however, been some softening of the provisions precluding distribution companies from owning or controlling generating plant. From the outset, distributors were allowed to retain up to five MW of generation capacity. They are, however, now allowed to own45:

- an unlimited amount of distributed generation that uses a new renewable energy source, although for geothermal and hydro plant above five MW the Minister’s approval is required;
- generating capacity up to 20 per cent of the network’s maximum demand or 50 MW, whichever is greater; and
- generating capacity used to provide reserve energy for the Commission.

The generation must be held in a legal entity separate from the lines business and be operated on an arms-length basis.

8.3 Part 4A of the Commerce Act 1986

Another regulatory constraint on distribution businesses is that like Transpower they are subject to the Commerce Commission’s targeted control regime under Part 4A of the Commerce Act 1986. The Commerce Commission has imposed both a price path threshold and a quality threshold on each of the 28 distribution businesses subject to the provisions of the Act. The current thresholds will apply for five years until 31 March 2009.

To demonstrate compliance with the quality threshold, a lines business must satisfy:

- a reliability criterion, requiring no material deterioration in quality; this is assessed on an annual basis; and
- a consumer engagement criterion, requiring that the business has meaningfully engaged with consumers to determine their demand for service quality; this is assessed every two years.

The price path threshold takes the form of CPI minus X per cent, meaning that the distributor will breach the threshold if its average price changes at an annual rate exceeding the change in the consumer price index (CPI) less the annual rate of X per cent that

45 Electricity Industry Reform Act 1998, ss.46A and 46C.
has been set by the Commerce Commission for the distributors. The X for each business is made up of three factors:

- a B-factor reflecting expected industry-wide improvements in total factor productivity; this has been set at one per cent for all distributors;
- a C1-factor reflecting the relative productivity of the distributor compared with others; this is set at either one per cent, zero per cent or minus one per cent depending on whether relative productivity is low, medium or high; and
- a C2-factor reflecting the relative profitability of the distributor compared with others; this is set at either one per cent, zero per cent or minus one per cent depending on whether relative profitability is high, medium or low.

The X-factor for each distributor is the sum of these three components; it ranges between two per cent and minus one per cent.

The information disclosure requirements on lines businesses that were formerly the responsibility of the Ministry of Economic Development have become the responsibility of the Commerce Commission46.

46 Commerce Act 1986, s.57T.
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