Appendix B Overview of the evolution of transmission pricing

1 The key phases in the evolution of transmission pricing in New Zealand from 1988 to the present are summarised below. This overview is based on a report prepared for the Electricity Commission in 2009.[1]

1988 to April 1996 – Unbundling of Bulk Supply Tariff and introduction of Transmission Pricing Methodology

2 In 1988, Transpower New Zealand Limited (Transpower[2]) was separated from the Electricity Corporation of New Zealand (ECNZ) and a detailed pricing structure was developed which intended to provide open and equal access to the transmission system for all parties.

3 The initial transmission pricing methodology (TPM) was developed from the Bulk Supply Tariff (BST). Between 1988 and 1991 there was a gradual unbundling of the BST into a series of pricing options for customers. The first real separation of the energy and transmission services provided by ECNZ was part of the so-called Nominated Quantity Option, which was offered to transmission customers in 1991.

4 The 1988 to April 1996 TPM is described in the following table.

Charge	Nature of charge	Paid by:
Connection	Cost of assets at point of connection	Generators; distributors; direct-connect
Constraint	Average of 6 highest winter day demand (MW) above threshold	Distributors; direct-connect
Network Capacity	Average of 3 years winter TOU usage (MWh)	Distributors; direct-connect
Transmission Service	Average of 7 years winter day demand (MW)	Distributors; direct-connect
HVDC	Allocation of pole 1 to generation and pole 2 to distributors/direct-connect	47% to Contact/ECNZ; 53% to distributors/direct-connect
System Support	Ancillary services (per kw supplied)	Generators

5 The Nominated Quantity Option was subsequently improved, enabling the unbundling of the BST to occur with minimal impact on customers. Supply contracts were separated into energy and transmission components[3] in October

[1] Strata Energy, *Report on Transmission Pricing Methodologies - 1988 to 2008*, June 2009. Available on the Authority's website at www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/stage1. The report sets out a more in-depth account of the various TPMs used in New Zealand and their development.

[2] Then called Trans Power. This appendix will use Transpower.

[3] Transpower Annual Report 1993/94.

1993 and the “revenue neutral” approach adopted, whereby the total paid by any customer for transmission and energy was unchanged as a result of the split. These contracts were rolled over on 1 April 1994, when Transpower was separated from ECNZ and became a standalone State-Owned Enterprise (SOE).

6 As part of the separation of the contracts and the subsequent separation of Transpower from ECNZ, a transitional revenue neutral pricing arrangement was introduced to ensure that customers were not subjected to high price increases as a result of the separation.

April 1996 to October 1996 – Transition to the New Zealand Electricity Market (NZEM)

7 The TPM of the time was evolved to meet the needs of the newly developed wholesale electricity market and a number of innovations were introduced to address customer concerns about the TPM.

8 In December 1995, Transpower notified its customers of a change to the pricing applicable from 1 April 1996.[4] The April 1996 to October 1996 TPM is described in the following table.

Charge	Nature of charge	Paid by:
Connection	Cost of assets at point of connection	Generators; distributors; direct-connect
Capacity	Residual after connection and HVDC.	Distributors; direct-connect
Demand (1) or	Nominated demand entitlement, with an excess demand charge for excess demand on winter weekdays (MW)	Distributors; direct-connect
Demand (2)	Demand entitlement based on previous year's winter peak demand (MW) (default option)	Distributors; direct-connect
Network	For use of network assets. Based on load flow analysis to produce average asset allocation based on usage from 1987/88 (MWh)	Generators; distributors; direct-connect
HVDC	Allocation of pole 1 to generation and pole 2 to distributors/direct-connect	47% to Contact/ECNZ; 53% to distributors/direct-connect

[4] Transmission Charges: Application of the Price Methodology for the 1996/97 Contract Year. Transpower, November 1995.

9 The purpose of the April 1996 to October 1996 TPM was to:

(a) introduce optimised replacement cost (ORC) for the purpose of calculating Network and Connection charges. The allocation of network asset usage would continue to be based on network load flow analysis;

(b) value high voltage alternating current (HVAC) and HVDC assets separately because the economic life for the HVDC assets was considered to be significantly shorter than that of the HVAC assets;

(c) average the routine maintenance expenditures that accrue to individual network and connection assets;

(d) split the old Capacity Charge into a new Capacity Charge (50%) and a Demand Charge (50%); and

(e) introduce two Demand Charge options:

(i) a contracted Demand Entitlement (DE) nominated by each customer, with an Excess Demand Charge (EDC) for excess demand on winter weekdays; and

(ii) a DE (based on the previous year's winter peak demand) with an Incremental Reset when, and if, the DE during winter was exceeded leading to a new DE which would be maintained until exceeded (default option for customers without transmission contracts).

October 1996 to April 1998 – Self regulation

10 In July 1996, further changes were made when Transpower notified its customers of the pricing methodology that would apply from 1 October 1996. This notification was updated in October 1996.[5] The reasons for the changes related to "a determination to change what was largely an asset cost-based pricing regime to one that over time would become more service focused and more responsive to individual customer requirements".[6]

11 The October 1996 to April 1998 TPM is described in the following table.

Charge	Nature of charge	Paid by:
Connection	Cost of assets at point of connection	Generators; distributors; direct-connect
Access	Residual after Transport and HVDC charges	Distributors; direct-connect
Transport	Based on load flow (MWh)	Distributors; direct-connect

5 Pricing for Transmission Services: Second Edition. Transpower, October 1996.

6 Pricing for Transmission Services. Introduction to the pricing methodology to be applied from 1 October 1996, Transpower, October 1996.

Charge	Nature of charge	Paid by:
HVDC	SI generators based on maximum injection	SI generators

12 The changes were:

(a) to replace Capacity and Demand charges with an Access charge;

(b) to replace Network charges with Transport charges;

(c) to recover, via Connection charges, the cost of assets required to connect a specific user to the grid. This extended the boundary of existing generator connections to include a greater share of user-specific connection assets (so called “deep connection”);

(d) to recover, via a MWh Transport charge determined using load flow analysis, future avoidable costs from all grid users. This was to ensure that the marginal price signal faced by grid users was the incremental cost of connection to the grid;

(e) to recover, via Access and Transport charges, unavoidable (sunk) costs from offtake customers only. This was to ensure that fixed transmission costs could not be avoided and that the signals for new investment were not distorted;

(f) to recover the full cost of the HVDC link from South Island generators and paying the HVDC losses and constraints rentals to South Island generators;

(g) to continue the use of caps on price increases, but based on the rate ($/kW) not the dollar amount;

(h) to extend the nominated Demand Entitlement and Demand Charge offer to completely replace the 10-year rolling average-based Capacity Charge and allowing for downward adjustments on the Incremental Reset; and

(i) to introduce Price Blocks for Access and Transport Charges to provide forward nomination of maximum demand for up to five years. Payment was through the Access and Transport rates multiplied by the Nominated Demand for each Price Block. Additional charges were paid for Excess Demand, which occurred when Demand exceeded Nominated Demand. There were 3 options for Excess Demand Charges which were subject to adjustments, depending on the option chosen (300:1, 200:1 or 100:1).

April 1998 to April 1999 – More self-regulation

13 In April 1998, Transpower announced more changes to the methodology:

(a) the 300:1 Excess Demand Option was no longer available;

(b) a 50:1 Excess Demand Option was introduced; and

(c) price blocks were limited to one year rather than five years.

April 1999 to April 2008 – Introduction of three current charges

14 In April 1999, Transpower announced an enhancement to the transmission pricing methodology applicable from 1 April 1999.[7] The April 1999 to April 2008 TPM is described in the following table.

Charge	Nature of charge	Paid by:
Connection	Cost of assets at point of connection	Generators; distributors; direct-connect
Interconnection	Residual after Connection and HVDC charges. Allocated on Anytime Maximum Demand	Distributors; direct-connect
HVDC	SI generators based on maximum anytime injection	SI generators

15 The key differences from the previous methodology are summarised below:

(a) three charges were introduced:

(i) connection charges for all generators and offtake customers for assigned connection assets; created a new definition for connection asset, which removed the previous distinction between "deep connection" assets for generators and "shallow connection" assets for offtake;

(ii) interconnection charges for offtake customers only allocated by peak demand ($/kW); removed the Transport charge which allocated 50% of the AC grid assets using a load flow model and the Access charge which recovered the residual revenue requirement. The interconnection charge recovered the residual revenue not recovered from other charges; and

(iii) HVDC charges for South Island generators only, allocated by peak injection MW; and

(b) a proportion of overhead was allocated to generators through Connection and HVDC charges. Previously, overhead had been recovered through Access charges;

(c) demand allocation was based on an incremental reset up or down to the average of p highest peaks in the last 12 months (where p=12 for that and subsequent years, until the TPM applicable from 1 April 2008 took effect).

[7] Pricing for Transmission Services, Pricing Methodology Fourth Edition, Transpower, April 1999.

16 This methodology remained in place until the current TPM was approved by the Minister of Energy in 2007 (and applied from April 2008) in accordance with the provisions of Part F of the Electricity Governance Rules (EGRs).

17 The revenue requirement from year to year had been subject to an Economic Value Adjustment (EVA) from 1998/99. The EVA adjusted the revenue requirement for economic gains or losses arising from optimised deprival value (ODV) valuation effects and incremental costs and revenues arising from non-transmission activities (shareholder account) and other non-shareholder related gains or losses (customer account).

April 2008 to present – Regulation

Development of TPM by Electricity Commission under Part F of the EGRs

18 The failure of the New Zealand electricity industry to agree on a self-regulating rulebook led to the establishment of the Electricity Commission in 2003 and the introduction of the rules for Transmission (Part F of the EGRs). The introduction of the EGRs led to significant changes in how Transpower obtained approval for its TPM.

19 The TPM applicable from 1 April 2008, which was approved by the Minister in 2007, was the culmination of the process set out in Part F of the EGRs that began in 2004. The main differences from the previous TPM were:

(a) connection charges:

(i) a replacement cost of assets (adjusted to preserve the last optimised values) and a revised definition of connection assets were introduced. With the Grid Investment Test (GIT) supposedly providing for efficient investment, valuation could move away from ODV and the use of replacement costs provided the most practical and stable price path;[8]

(ii) allocation of shared connection assets was based on the anytime maximum demand for offtake and on the anytime maximum injection for generators; and

(iii) the anytime maximum demand/injection was the average of the 12 highest values for the capacity measurement period for the relevant pricing year; and

(b) interconnection charges:

(i) the costs of interconnection assets were allocated to offtake customers by average regional coincident peak demand (RCPD), which was designed to give a locational pricing signal for load management and new investment;

[8] Transmission Pricing Methodology, Supplementary Material, Transpower, June 2006.

(ii) the average RCPD was calculated using 12 peaks in the upper North Island (UNI) and upper South Island (USI), and 100 peaks in the lower North Island (LNI) and lower South Island (LSI);

(iii) a consequential effect of the introduction of RCPD charging was the aggregation of multiple points of connection for the purpose of determining a customer's maximum demand charges; and

(iv) the interconnection charges for a pricing year were fixed on the basis of the RCPD for the previous capacity measurement period.[9] This resulted in lower transaction costs; facilitated the pass-through of transmission costs by distribution owners; and made the charges more fixed and unavoidable; and

(c) HVDC revenue requirement allocated to South Island injection customers on the basis of historical anytime maximum injection (HAMI). The HAMI is the highest peak injection over the most recent and the four preceding capacity measurement periods. This approach was intended to reduce incentives to avoid HVDC charges.[10]

20 In April 2009, the Electricity Commission initiated a review of the TPM and established the Transmission Pricing Technical Group (TPTG) to provide technical advice on the TPM review project. In October 2009, the Electricity Commission consulted on high level options for transmission pricing. A further round of consultation was undertaken by the Electricity Commission in July 2010.

21 The Electricity Authority was established in November 2010, and the Authority continued the TPM review project initiated by the Electricity Commission. In February 2011, the Authority consulted on a proposal to remove the pricing principles. The Authority established the Transmission Pricing Advisory Group (TPAG) to assist with the TPM review, and provide independent advice on a recommended option for the TPM. The TPAG reported to the Authority in September 2011, but was unable to reach a consensus on key aspects of transmission pricing.

22 The Authority consulted on a decision-making and economic framework for transmission pricing in January 2012, and finalised the framework in May 2012. The framework established the Authority's preferred hierarchy of pricing approaches for the TPM and supported the objective of promoting efficiency in the electricity industry for the long-term benefit of consumers.

[9] The 12 month period from 1 September to 31 August immediately prior to the commencement of the pricing year, which is the period from 1 April to 31 March in respect of which Transpower calculates its prices.

[10] Ibid.