

Distribution Pricing Methodology

Consultation paper on a model approach

Prepared by the Electricity Commission

5 June 2009

Executive summary

This consultation paper proposes a voluntary model approach to a distribution pricing methodology (**the proposed model approach**).

Key reasons for the development of the proposed model approach include:

- charging for distribution services in a way that:
 - encourages the efficient use of electricity by end users;
 - encourages efficient investment in distribution, transmission, distributed generation (including renewable generation), and technology innovation;
 - maintains or enhances investment in energy efficiency and demand-side management;
 - signals the full costs of transporting each additional unit of electricity to users; and
- enhances competition in the retail electricity market.

The proposed model approach, if implemented, therefore furthers the Electricity Commission's (**Commission's**) principal objectives, as outlined in the Electricity Act 1992 (**Act**), which are:

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

The proposed model approach also gives effect to the objective in paragraph 100 of the Government Policy Statement on Electricity Governance dated May 2009 (**GPS**), which states that "*the Commission should develop, in consultation with interested parties, principles or model approaches to distribution pricing and monitor their uptake*". One of the functions of the Commission is to give effect to GPS objectives and outcomes.

Consistent with the outcome of the distribution pricing process facilitated by the Electricity Networks Association (**ENA**) in 2004 - 2005, which culminated in the report of the Pricing Approaches Working Group (**PAWG**), the Commission considers that a single model approach for distribution pricing, with flexibility in its implementation, is the most efficient means of furthering the objectives described above.

There are sound reasons for pursuing a proposed model approach, which include enabling distributors to decide on how consistent their methodologies should be with the model approach by applying economic criteria in their decision making. The Commission would then evaluate the differences between a distributor's approach and the proposed model approach, and factor this evaluation into any changes to the proposed model approach over time (including consideration as to whether a mandatory approach is preferable).

The Commission acknowledges that there are many complexities with distribution pricing, reflecting individual network design and capacity utilisation, geographical differences, historical pricing and cross subsidies, and network amalgamations. It would be a complex, lengthy and probably impractical exercise to develop a mandatory approach that could be applied to 29 distributors.

With a proposed model approach, the Commission's expectation is that distributors will seek to align their pricing methodologies over time, making transparent decisions about the costs versus the benefits of making their methodologies consistent with the proposed model approach. The Commission expects that distributors will report on variations from the proposed model approach to enable monitoring of uptake by the Commission.

The proposed model approach is based on the approach recommended by the PAWG in early 2005, which was the culmination of approximately four years of effort by the industry. The Commission has communicated this process to stakeholders since the commencement of the distribution pricing project. The Commission considers the PAWG model approach to be robust, and understands that, at the time of its development, it received widespread acceptance from distributors and retailers. Therefore, the Commission considers that the PAWG model approach forms a sound basis on which the Commission can move forward with its proposed model approach.

To guide the development of the proposed model approach, the Commission has developed a set of guiding principles. These build on the guiding principles used by the PAWG, and take into account the Commission's objectives and required outcomes, as set out in the Act and the GPS.

The PAWG approach has been updated primarily to reflect changes in the regulatory environment. These changes reflect the development of the transmission pricing methodology, and regulations pertaining to distributed generation and low fixed charges for domestic consumers. In addition, the proposed model approach differs from the PAWG approach in that it makes firm recommendations on disaggregating costs by service level and on adopting the retail delivery model (where model distributors charge retailers on the basis of sales volumes measured at the ICP) over the wholesale delivery model (where distributors charge retailers on the basis of reconciled sales volumes at grid exit points).

Although the wholesale delivery model offers advantages to distributors such as lower revenue risk and lower administration costs, the Commission believes that the retail delivery model offers a wider range of benefits including increased cost-reflectivity and reduced cross-subsidisation between general connections, greater transparency of distribution prices, and better enabling costs to be disaggregated to reflect service level differences. While proponents of the wholesale delivery model argue that it provides retailers with greater flexibility in the setting of retail prices than does the retail delivery model, the Commission notes that retailers could rebundle distribution tariffs under the retail delivery model and thus have the same flexibility as under the wholesale delivery model, as there is no requirement for retailers to pass through distribution prices in the form set out by the distributor. The

Commission acknowledges that, if retailers do choose to rebundle, then price signals could be distorted.

The proposed model approach relates only to standard distribution services. The Commission considers that additional services that a distributor may choose to offer, such as enhanced quality above a standard service level and additional controllable/interruptible load services for the wholesale electricity market should not form part of a model approach; their application and pricing should be determined by the distributor (subject to any applicable price/quality regulation).

The Commission also notes that distributors' total target revenue requirements (as opposed to the methodology for recovering that requirement) are set (in the case of non-exempt distributors) in accordance with the regulatory arrangements under the Commerce Act, overseen by the Commerce Commission. One group of input methodologies the Commerce Commission is required to set under Part 4 of the Commerce Act 1986 (to the extent such methodologies may be applicable to the type of regulation under consideration) are pricing methodologies. While the Commerce Commission is not bound by the Commission's model approach to a distribution pricing methodology, it is required to take it into account. Accordingly, the two Commissions are working together to ensure the two work streams are aligned and clarifying respective roles for the industry.

In summary, the proposed model approach aims to improve the transparency of the allocation of costs, in particular load-dependent costs, and to facilitate efficient pricing. It aims to promote efficient use of distribution networks and efficient investment in these networks, by signalling the cost of network congestion and augmentation, while ensuring that distributors and consumers receive stability and certainty in revenues and costs (respectively). Finally, the proposed model approach aims to achieve a greater degree of commonality and consistency of distribution pricing, thereby reducing the complexity and costs faced by retailers and thus enhancing retail competition.

The consultation paper seeks feedback on the Commission's proposed model approach and associated implementation issues. The paper also outlines the process for finalising the proposed model approach and the expected timing for doing so.

Glossary of abbreviations and terms

Act	means the Electricity Act 1992
ADR	means automated demand response
AMD	means “anytime maximum demand”, which is a load group’s after diversity anytime maximum demand calculated or assessed by using the average of 200 of the load group’s maximum half-hour demands over a year (i.e. 100 hours)
AMI	means advanced metering infrastructure
Anytime maximum demand (TPM AMD)	means a network’s after diversity anytime maximum demand on the grid calculated or assessed by using Transpower’s transmission pricing methodology
Commerce Act	means the Commerce Act 1986 (as amended)
Commission	means the Electricity Commission
Consumer	(a) means any person who is supplied, or who applies to be supplied, with electricity; but (b) does not include any generator or distributor or retailer, except where the generator or distributor or retailer, as the case may be, is supplied with electricity for its own consumption and not for the purposes of resupply to any other person
Consumer-specific costs	means costs incurred by a distributor to provide equipment or services that it would not incur but for the exclusive requirements of that consumer
DG Regulations	means the Electricity Governance (Connection of Distributed Generation) Regulations 2007
Distributor	means any electricity industry participant who owns or operates a network (that is not an embedded network) other than Transpower and includes an ELB
Electricity lines business (ELB)	means a supplier of electricity lines services, other than Transpower
Electricity lines services	has the meaning set out in section 54C of the Commerce Act
ENA	means the Electricity Networks Association
General connection	refers to the connection category or load group category that is not ‘large major connection’ or ‘major connection’

GPS	means the Government Policy Statement on Electricity Governance, released in May 2009
GXP	means a grid exit point as defined in part A of the Rules
ICP	means a point of connection on a local network or embedded network, having the attributes set out in rule 1 of schedule E1 of the Electricity Governance Rules 2003
Large major	refers to the connection category or load group category that is supplied from the sub-transmission network (and so is deemed to use the sub-transmission assets only)
Load-dependent costs	means costs incurred by a distributor to provide network capacity to supply the load on its network
Load group	means a category of consumers from which load-dependent costs will be recovered
Load-independent costs	means costs incurred by a distributor to provide distribution services but which are neither directly related to the network capacity nor consumer-specific costs
Long run average incremental cost (LRAIC)	The LRAIC is calculated by considering the incremental cost of providing the capacity to distribute to the existing maximum load over the life cycle of the network assets. This calculation involves consideration of the annualised load-dependent costs, generally calculated as the optimised replacement cost (ORC) of the assets multiplied by an annual capital recovery factor plus the annual operating and maintenance costs
Low Fixed Charge Regulations	means the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004
Major	refers to the connection category or load group category that is supplied from the 11kV network (and so is deemed to use the 11kV and all higher voltage distribution assets)
Network	means the lines, and associated equipment, owned or operated by a distributor in a contiguous geographic area or areas
Network asset group	means a group of shared network assets for which the costs may be distinguished from the costs of other groups of shared network assets and may be defined in terms of their location and/or voltage levels
ORC	means optimised replacement cost
PAWG	means the Pricing Approaches Working Group, which was a consultative group formed by the Electricity Networks Association for the purpose of developing voluntary model approaches to distribution pricing in New Zealand

PAWG model approach	means the recommended model approach for distribution pricing set out in the PAWG report
PAWG report	Means the PAWG report, <i>Model Approaches to Distribution Pricing</i> dated February 2005
RCPD	means a network's regional coincident peak demand on the regional transmission grid and which is calculated or assessed in accordance with Transpower's transmission pricing methodology
Retail delivery model (RDM)	means an electricity distribution business model used by a distributor in which ICP metered/estimated quantities are used by the distributor for charging retailers
Retailer	has the meaning set out in part A of the Rules
Rules	means the Electricity Governance Rules 2003
Time-of-use	refers to a description of the distribution delivery service according to the times at which the service is (or is not) provided
TPM	means the transmission pricing methodology set out in Schedule F5 of the Rules
UFE	means unaccounted for electricity
Wholesale delivery model (WDM)	means an electricity distribution business model in which reconciled GXP-metered quantities are used by the distributor for charging retailers

Contents

Executive summary	A
Glossary of abbreviations and terms	E
1. Introduction	1
1.1 Purpose of this paper	1
1.2 Reasons for the development of a model approach	2
1.3 The proposed model approach – process	3
1.4 Format of consultation paper	5
1.5 Submissions	7
2. Reasons for proposing a model approach	9
2.1 Introduction	9
2.2 A proposed model approach	10
2.3 Static efficiency	10
2.4 Dynamic efficiency	11
2.5 Enhanced retail competition	11
2.6 Furthering Commission objectives	12
2.7 Conclusion	12
3. Distribution pricing in New Zealand	13
3.1 Introduction of distribution pricing	13
3.2 The PAWG	13
3.3 The PAWG model – summary of main features	13
3.4 Overview of PAWG model pricing-setting process	15
3.5 Distributor business models in New Zealand	17
4. Summary of regulatory and contractual arrangements	18
4.1 Introduction	18
4.2 Setting the target revenue requirement	18
4.3 Allocating the target revenue requirement	20
4.4 Distribution agreements with customers	21
4.5 Other legislation potentially affecting pricing methodologies	22

5.	Guiding principles for the proposed model approach	23
5.1	Introduction	23
5.2	Commission objectives and required outcomes	23
5.3	PAWG guiding principles	25
5.4	Discussion	26
5.5	Proposed guiding principles	26
6.	Distributor business models	28
6.1	Introduction	28
6.2	Retail delivery model (RDM)	28
6.3	Wholesale delivery model (WDM)	28
6.4	Use of each business model in New Zealand	30
6.5	Pricing signals	30
6.6	Management of losses	32
6.7	Costs	33
6.8	Other jurisdictions	34
6.9	Discussion and comparison against guiding principles	34
6.10	Conclusion	38
6.11	Proposal	39
7.	Distribution pricing model	40
7.1	Approach	40
8.	Cost categorisation	42
8.1	Introduction	42
8.2	Consumer-specific costs	42
8.3	Load-dependent costs	42
8.4	Load-independent costs	43
8.5	Generation-specific costs	43
9.	Cost Allocation	44
9.1	Introduction	44
9.2	Allocation method	44
9.3	Allocate consumer-specific costs	44
9.4	Allocate generation-specific costs	44
	Allocating distributed generation costs and benefits	44

9.5	Allocate load-dependent costs	45
	Allocating load-dependent costs to network asset groups	45
	Allocating network asset group costs to load groups	47
	Allocating transmission costs	49
	Allocating controllable load costs and benefits	51
9.6	Allocate load-independent costs	51
9.7	Deferring network augmentation	51
10.	Price signalling	54
10.1	Introduction	54
10.2	PAWG model approach to price signalling	54
10.3	Discussion	54
10.4	Price signalling proposal	56
10.5	Price structure proposal	56
11.	Model price structure	57
11.1	Introduction	57
11.2	PAWG model approach to determining a price structure	57
11.3	PAWG's model price structure	58
	Half-hourly metered consumers	59
	Non-half-hourly metered consumers	59
11.4	Discussion	59
11.5	Proposed further development of price structures	61
12.	Meeting the Guiding principles	62
12.1	Consideration against guiding principles	62
12.2	Conclusion	64
13.	Implementation issues and next steps	65
13.1	Transition to implementation	65
13.2	Monitoring the uptake	65
13.3	Next steps	67
Appendix 1	Commission's principal objectives and specific outcomes as set out in the Electricity Act	69

Appendix 2	Requirements for the distribution methodologies as set out in the 2009 GPS	70
Appendix 3	Regulated distributor tariff option provisions in Low Fixed Charge Regulations	71
Appendix 4	Pricing principles in DG Regulations	74
Appendix 5	Submission questions	77
Appendix 6	Format for submissions	78

Tables

Table 1:	Business model comparison against guiding principles	36
Table 2:	Allocation of load-dependent costs to asset groups by supply voltage	47

Figures

Figure 1:	PAWG model approach to a distribution pricing methodology	14
Figure 2:	WDM and RDM allocation of load dependent costs	29
Figure 3:	Distribution pricing methodology	40
Figure 4:	Allocation of load-dependent costs	46

1. Introduction

1.1 Purpose of this paper

- 1.1.1 The purpose of this consultation paper is to outline the Electricity Commission's (**Commission's**) proposed guiding principles to a proposed model approach to a distribution pricing methodology (the **proposed model approach**), set out the proposed model approach itself, and seek submissions on both of them.
- 1.1.2 The paper begins by setting out the history of distribution pricing in New Zealand, the Pricing Approaches Working Group (**PAWG**) model, and the process for developing the proposed model approach for consultation. The paper then summarises the regulatory and contractual arrangements in New Zealand that affect the proposed model approach, before setting out guiding principles against which the proposed model approach can be assessed.
- 1.1.3 The proposed model approach is split into four stages: cost categorisation, cost allocation, model price structures and the model price schedules. This paper also includes a recommended timetable for implementation and consultation questions.
- 1.1.4 The Commission invites submissions on the proposed model approach. In particular, the Commission welcomes submissions on:
- (a) the reasons for the Commission determining a model approach to a distribution pricing methodology;
 - (b) the use of the PAWG model approach as the basis for the proposed model approach;
 - (c) the guiding principles used to guide the development of the proposed model approach;
 - (d) the benefits and costs of the proposed model approach adopting only one business model (the retail delivery model) rather than two business models (the retail delivery model and the wholesale delivery model);
 - (e) the treatment of distributed generation and transmission pricing in the proposed model approach;
 - (f) the allocation of net benefits of deferred network augmentation in the proposed model approach;
 - (g) the proposed approach to cost categorisation and cost allocation;
 - (h) the proposed approach to price signalling and the model price structure; and
 - (i) issues associated with implementing the proposed model approach.

1.2 Reasons for the development of a model approach

1.2.1 Key reasons for the development of a model approach include:

- (a) charging for distribution services in a way that:
 - (i) encourages the efficient use of electricity by end users;
 - (ii) encourages efficient investment in distribution, transmission, distributed generation (including renewable generation), and technology innovation;
 - (iii) maintains or enhances investment in energy efficiency and demand-side management;
 - (iv) signals the full costs of transporting each additional unit of electricity to users; and
- (b) facilitating competition in the retail electricity market – in the Commission’s recent Market Design Review, retailers overwhelmingly supported standardising network pricing approaches as a means to reducing the transaction costs faced by retailers competing for electricity consumers across distribution networks.

1.2.2 Implementing a model approach therefore furthers the Commission’s principal objectives and specific outcomes (set out more fully in Appendix 1), as outlined in the Electricity Act 1992 (**Act**), which are:

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

1.2.3 A model approach also gives effect to the objective in paragraph 100 of the Government Policy Statement on Electricity Governance dated May 2009 (**GPS**), which states that “*the Commission should develop, in consultation with interested parties, principles or model approaches to distribution pricing and monitor their uptake*”.

1.2.4 The Commission considers that a single approach for distribution pricing, with flexibility in its implementation, is the most efficient means of delivering the benefits described above. This is consistent with the outcome of the distribution pricing process facilitated by the Electricity Networks Association (**ENA**) in 2004 - 2005, which culminated in the PAWG report.

1.3 The proposed model approach – process

1.3.1 In preparing this consultation paper the Commission has:

- (a) reviewed the model approaches to distribution pricing in New Zealand set out in the PAWG report published in February 2005¹;
- (b) considered the recommendations of the PAWG report and accepted the model pricing methodology (**PAWG model approach**) as the starting point for the Commission's proposed model approach;
- (c) reviewed the various regulatory arrangements that have come into effect subsequent to the publication of the PAWG report. These include:
 - (i) the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (**Low Fixed Charge Regulations**);
 - (ii) the transmission pricing methodology (**TPM**) set out in Schedule F5 of the Electricity Governance Rules 2003 (**Rules**);
 - (iii) the Electricity Governance (Connection of Distributed Generation) Regulations 2007 (**DG Regulations**); and
 - (iv) the relevant sections of the (recently revised) Commerce Act 1986 (**Commerce Act**);
- (d) considered the GPS;
- (e) reviewed the pricing methodology of the four largest distributors to identify the extent to which the recommendations in the PAWG report have been implemented by these distributors;
- (f) through the ENA, requested that all distributors report on the extent to which they have implemented the recommendations in the PAWG report (this engagement is described more fully below in paragraphs 1.3.2 to 1.3.9);
- (g) given consideration to the potential implications on distribution pricing of advanced metering infrastructure (**AMI**)² and automated demand response (**ADR**)³, which overcome limitations in current non-half-hourly metering with respect to price signals, by enabling two-way communication to the ICP level for general connections.

1.3.2 In order to understand better what changes in distribution pricing had occurred since the PAWG report was published, the Commission sought to engage

¹ See PAWG, *Model Approaches to Distribution Pricing: Second Paper*, dated 2 February 2005. The PAWG report can be found at <http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/distrib-pricing/PAWG-paper.pdf>.

² AMI by definition has two-way communication capability.

³ ADR can be programmed by the consumer or the supplier to initiate demand response to price signals.

distributors through the ENA and via the Commission's website and updates. The Commission asked distributors to report on how their pricing methodology had changed since 2005 and, in particular, what steps they had taken in implementing the PAWG recommendations.

- 1.3.3 As at the date of this paper, only Counties Power, Aurora, Northpower, and PowerNet have engaged with the Commission.
- 1.3.4 The information received can be summarised as follows:
- (a) Counties Power advised that it has not substantially altered its pricing methodology in the last five years and that it has started a methodology review taking into account the PAWG report;
 - (b) Aurora Energy advised that it applies the retail delivery model (i.e. it utilises Installation Control Point (ICP) based pricing). Its pricing methodology largely reflects the PAWG recommendations;
 - (c) PowerNet advised that it has incorporated the majority of the recommendations outlined in the PAWG report. Its network companies use the wholesale delivery model rather than the retail delivery model. PowerNet is currently considering switching to the retail delivery model and, to this end, has invested money and resources in an upgrade of its ICP database, which provides PowerNet with the ability to process retailer supplied consumption files and analyse potential risks and benefits of a change to the retail delivery model; and
 - (d) Northpower advised that, at a high level prior to 2005, its pricing was consistent with the PAWG recommendations and since that time significant changes have been made to improve consistency at a more detailed level.
- 1.3.5 The ENA Board has been briefed on two occasions. The first briefing in February 2009 was to announce the project and to note the:
- (a) project's purpose;
 - (b) high level work plan, with the PAWG paper to be used as the starting point for the analysis; and
 - (c) an initial preference for a voluntary approach, which the lines businesses can be evaluated and monitored against.
- 1.3.6 The second briefing, on 30 April 2009, was to update the ENA Board on the progress to date, noting:
- (a) the Commission has reviewed the pricing methodologies of the four largest distributors;

- (b) in addition, the four distributors had responded to the Commission's general request for information. From the responses it appears that not all businesses have implemented the PAWG recommendations; and
- (c) the Commission's draft model approach to distribution pricing has used the recommendations made in the PAWG paper as the starting point.

1.3.7 In late April 2009, the Commission met with the ENA and the representative of two large distributors, to discuss the Commission's suggested changes to the PAWG recommendations.

1.3.8 A high level summary of the proposed amendments to the PAWG recommendations was provided and feedback invited. The feedback included:

- (a) the approach appears too prescriptive and recommends only one delivery model for pricing (retail delivery model). A cost/benefit analysis (CBA) should be undertaken to justify this preference;
- (b) the PAWG approach was prescriptive but offered distributors the choice between using the retail delivery model and the wholesale delivery model;
- (c) a "one size fits all" approach is unlikely to be suitable;
- (d) Orion commented that the wholesale delivery model does not dilute the price signal to individual consumers; and
- (e) the Commission should explain how its model approach translates into the Commerce Commission input methodologies.

1.3.9 The Commission's consideration of the above matters and the information it is seeking from interested parties form the basis for this consultation paper.

1.4 Format of consultation paper

1.4.1 The format of this consultation paper is outlined in the table below.

Section	Description
1. Introduction	Describes the purpose of the paper, summarises the process adopted in developing the proposed model approach and outlines the submission requirements.
2. Reasons for a model approach	Summarises the key reasons for developing a model approach.
3. Distribution pricing in New Zealand	Outlines the history of distribution pricing in New Zealand and overviews the PAWG model.

Section	Description
4. Regulatory and contractual arrangements	Summarises the key regulatory and contractual arrangements influencing the development of the proposed model approach.
5. Guiding principles for a model approach to distribution pricing	Lists the set of guiding principles developed and used by the Commission to guide the development of the proposed model approach.
6. Distributor business models	Discusses the merits of the two main business models used by distributors in New Zealand for distribution pricing and recommends a preferred model.
7. Distribution pricing model	Summarises the proposed model approach.
8. Cost categorisation	Describes the categorisation of a distributor's total revenue requirement into major cost categories.
9. Cost allocation	Describes the proposed approach to allocating costs to end users within each of the major cost categories.
10. Price signalling	Sets out the intent of the distribution price signals to be issued under the proposed model approach.
11. Model price structure	Sets out the proposed model price structures to be used as a guideline by distributors.
12. Meeting the guiding principles	Summarises the extent to which the proposed model approach meets the guiding principles.
13. Implementation issues and next steps	Seeks feedback on implementation issues associated with the proposed model approach and outlines the process and expected timing for finalising it.
Appendices	
1: Commission's principal objectives and specific outcomes as set out in the Electricity Act	Sets out the Commission's principal objectives and specific outcomes from section 172N of the Act.
2: Requirements for the distribution methodologies as set out in the 2009 GPS	Describes the Government's requirements in relation to distribution pricing methodologies.

Section	Description
3: Regulated distributor tariff option provisions in Low Fixed Charge Regulations	Sets out the provisions relating to regulated distributor tariff option in the Low Fixed Charge Regulations (regulations 13-17).
4: Pricing principles in DG Regulations	Sets out the pricing principles from Schedule 4 of the DG Regulations.
5: Submission questions	Repeats the Commission's questions.
6: Format for submissions	Describes the Commission's preferred format for submissions.

1.5 Submissions

1.5.1 The Commission's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Commission, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@electricitycommission.govt.nz with "Submission on Proposed Model Approach to Distribution Pricing Methodology – Consultation paper" in the subject line.

1.5.2 If submitters do not wish to send their submission electronically, they should post one hard copy of their submission to the address below.

Bronwyn Christie
Electricity Commission
PO Box 10041
Wellington 6143

Electricity Commission
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

Tel: 0-4-460 8860
Fax: 0-4-460 8879

1.5.3 Submissions should be received by 5 pm on 3 July 2009. Please note that late submissions are unlikely to be considered.

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

1.5.5 If possible, submissions should be provided in the format shown in Appendix 6. Your submission is likely to be made available to the general public on the Commission's website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Commission on a confidential basis. However, all information provided to the Commission is subject to the Official Information Act 1982.

2. Reasons for proposing a model approach

2.1 Introduction

- 2.1.1 In a competitive market, competition between market participants acts to incentivise those participants to deliver better outcomes. Economic efficiency can be thought of as:
- (a) static efficiency⁴ – using a given technology, the right combination of goods and services is produced at lowest cost for consumers at a price that consumers are willing to pay; and
 - (b) dynamic efficiency – efficient investment in resources occurs over time.
- 2.1.2 In markets with limited competition, there are not the same incentives to be economically efficient.
- 2.1.3 The distribution of electricity is an example of a market with limited competition. Because of issues associated with duplicating linear network assets, New Zealand's distributors are all monopolies in their local regions. Hence, regulation is used to incentivise distributors to deliver economic outcomes that more closely reflect competitive market outcomes. The regulation of distributors' prices can be simplified into ensuring two outcomes:
- (a) level of distribution prices is efficient; and
 - (b) structure of distribution prices is efficient.
- 2.1.4 In New Zealand, the Commerce Commission has primary responsibility for ensuring both the composition and level of prices are efficient. However, the Commission has been given the task (in accordance with its function to give effect to GPS objectives and outcomes) of developing principles or model approaches to distribution pricing. This requires the Commission to work closely with the Commerce Commission.
- 2.1.5 Due to the relatively large number of distributors in New Zealand, the potential exists for a wide range of distribution pricing structures, delivering a range of efficiency outcomes – some more efficient than others. To assist distributors in structuring their distribution prices so as to deliver the most economically efficient outcome, the PAWG report was produced.
- 2.1.6 The Commission considers the PAWG model approach to be robust and, although it has not yet been universally adopted by distributors, the Commission understands that, at the time it was released, it received widespread acceptance from distributors and retailers. Therefore, it appears appropriate to use the

⁴ Static efficiency is often broken down into productive efficiency and allocative efficiency.

PAWG report as the basis for an updated model approach to a distribution pricing methodology, which has as its primary drivers the economic goals of static and dynamic efficiency.

2.2 A proposed model approach

2.2.1 There are sound reasons for pursuing a proposed model approach rather than a compulsory one. These include enabling distributors to decide on how consistent their methodologies should be with the model approach by applying economic criteria in their decision making. The Commission would then evaluate the differences between a distributor's approach and the proposed model approach, and factor this evaluation into any changes to the proposed model approach over time (including consideration as to whether a mandatory approach is preferable).

2.2.2 The Commission acknowledges that there are many complexities with distribution pricing, reflecting individual network design and capacity utilisation, geographical differences, historical pricing and cross subsidies, and network amalgamations. It would be a complex, lengthy and probably impracticable exercise to develop a mandatory approach that could be applied to 29 distributors.

2.2.3 With a voluntary model approach, the Commission's expectation is that distributors will seek to align their pricing methodologies over time, making transparent decisions about the costs versus the benefits of making their methodologies consistent with the proposed model approach. The Commission expects that distributors will report on variations from the proposed model approach (Statement of Variations to the Voluntary Model Approach).

2.3 Static efficiency

2.3.1 Static efficiency requires the use of existing network assets to be optimised at the lowest cost to network users. To assist in achieving this, distribution prices should be structured in a manner which reflects the cost of the distributor operating and maintaining the network in order to supply the different types and locations of electric load.

2.3.2 Cost-reflective prices signal to consumers the network-related costs associated with taking a certain quantity (and quality) of load for a period of time in a particular part of the distribution network. By encouraging distributors to use cost-reflective pricing, a model approach to a distribution pricing methodology seeks to minimise cross-subsidisation and facilitates efficient use of the network by consumers.

2.4 Dynamic efficiency

- 2.4.1 Cost-reflective pricing also assists in achieving dynamic efficiency. This form of efficiency requires that efficient signals are provided for future investment and capacity levels in the distribution network and/or future investment in non-network alternatives.
- 2.4.2 Dynamic efficiency considerations are particularly important for capacity constrained distribution networks. In such instances, signalling to network users the incremental network augmentation costs associated with additional usage facilitates efficient inter-temporal decision making. Consumers may, for instance, incur the associated network augmentation costs, or they may move their consumption to other time periods. They may also look to invest in alternatives to distribution, such as distributed generation, or invest in new technologies that reduce their electricity consumption.
- 2.4.3 The PAWG report used the concept of long-run average incremental cost (**LRAIC**) as the basis on which to reflect incremental costs in prices. As the name suggests, this approach uses the long run average cost of providing capacity on a distribution network to calculate the incremental cost of providing network capacity. The Commission agrees with the use of LRAIC and therefore has retained it in the proposed model approach.

2.5 Enhanced retail competition

- 2.5.1 In addition to providing a mechanism for distribution prices to deliver economic efficiency, the benefits of a model approach, if taken up by distributors, also extend to the retail energy market. Through sharing a common approach to a distribution pricing methodology, distributors facilitate retail competition by reducing the transaction costs faced by retailers competing for electricity consumers across multiple distribution networks (e.g. reducing the complexity of the systems retailers have to use for pricing and billing) and address consumer concerns about a lack of transparency in distribution pricing. In the Commission's recent Market Design Review, retailers overwhelmingly supported standardising network pricing approaches as a means of reducing their transaction costs.
- 2.5.2 A model approach therefore should benefit consumers on smaller distribution networks where retailers do not have the same economies of scale in systems and processes to accommodate varying approaches to distribution pricing. It should also lower the barriers to entry into the retail electricity market.

2.6 Furthering Commission objectives

2.6.1 For the reasons described above, implementing a model approach furthers the Commission's principal objectives, as outlined in the Act, which are:

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

2.6.2 It also gives effect to the GPS, which articulates the Government's expectations in respect of the Commission putting in place arrangements to further the policy objectives described in the Act. With respect to distribution pricing, paragraph 100 of the GPS, in particular, states:

“The Commission should develop, in consultation with interested parties, principles or model approaches to distribution pricing and monitor their uptake.”

2.6.3 One of the Commission's functions in the Act is to give effect to GPS objectives and outcomes.

2.7 Conclusion

2.7.1 The Commission considers that developing a proposed model approach to a distribution pricing methodology furthers its principal objectives in the Act and gives effect to the relevant objectives in the GPS. It is an important step towards improving economic efficiency in New Zealand's distribution sector. The Commission believes that the approach will, if taken up, facilitate efficient use of existing network infrastructure and efficient investment in network and non-network alternatives over time. In addition, a model approach should also facilitate competition in the retail electricity market by reducing transaction costs. The quantum of these benefits and any likely costs associated with implementing the proposed model approach will be evaluated during the consultation process.

3. Distribution pricing in New Zealand

3.1 Introduction of distribution pricing

3.1.1 Separated distribution prices were first introduced in New Zealand following the separation of line and energy charges in 1993. A report by the Separation of Line and Energy Charges (**SOLEC**) Working Group⁵ proposed that distribution costs be allocated across six consumer groups, which in turn were based on their use of various network assets (i.e., their voltage levels) and their capacity requirement.

3.1.2 After the report of the Ministerial Inquiry into the Electricity Industry was published in May 2000, the government produced a GPS in December 2000⁶ which, among other matters, required an electricity industry governance board to develop model approaches to distribution pricing. This requirement has remained in each subsequent GPS.

3.2 The PAWG

3.2.1 The ENA and the Electricity Governance Establishment Committee⁷ agreed that ENA would establish a working group to develop model approaches to distribution pricing. The working group became known as the PAWG.

3.2.2 After publishing an initial discussion paper for consultation in May 2004, the PAWG published a further discussion paper in August 2004, which was then revised to incorporate consultation feedback and published the PAWG report.

3.3 The PAWG model – summary of main features

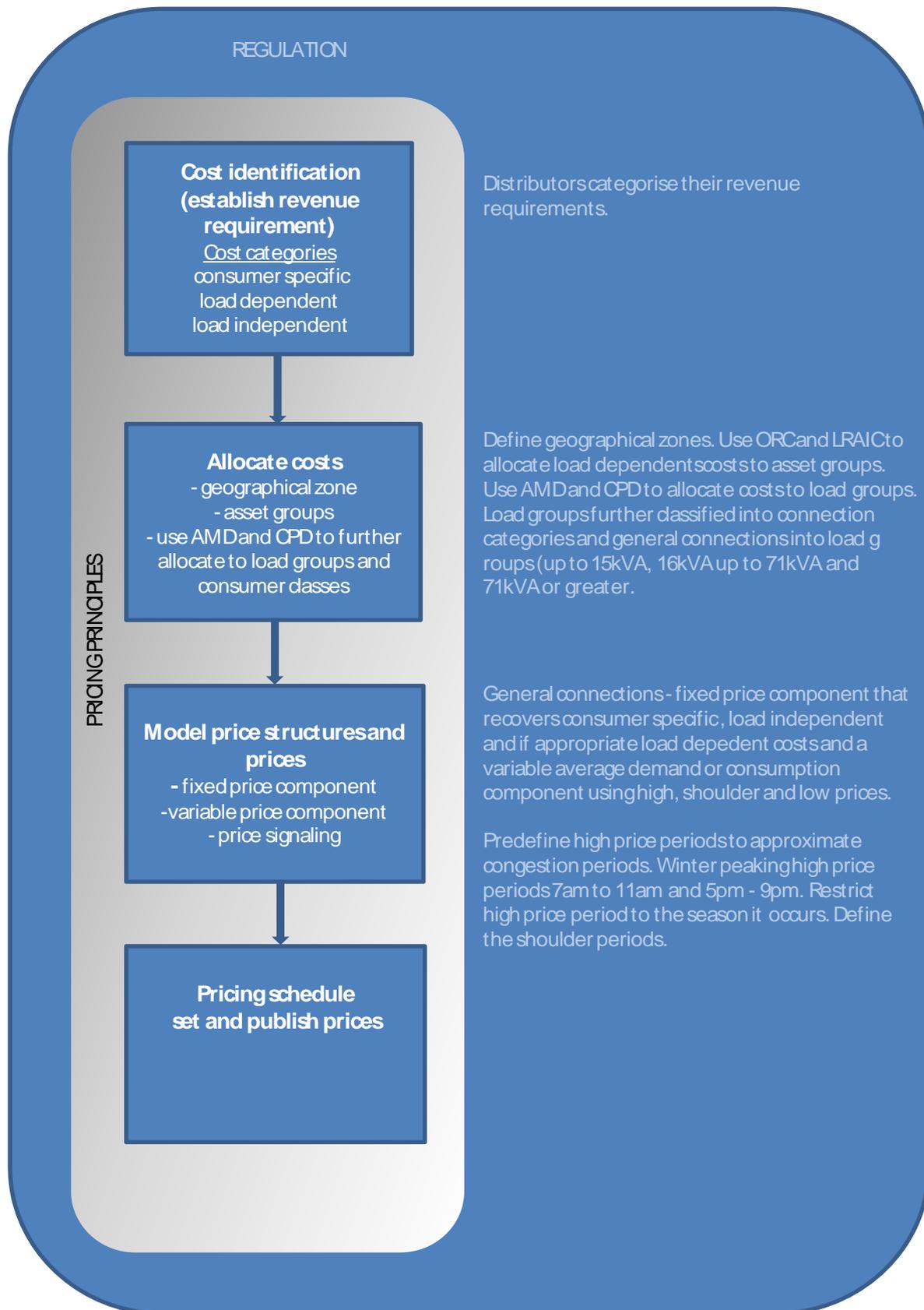
3.3.1 The PAWG report contained a recommended model approach for distribution pricing, the main features of which are summarised in Figure 1 below.

⁵ See Separation of Line and Energy Charges Working Group paper, *Guide to the Derivation of Line Charges*, dated January 1992.

⁶ Government Policy Statement: *Further Development of New Zealand's Electricity Industry*, December 2000.

⁷ The Electricity Governance Establishment Committee was set up to establish the electricity industry governance board that was intended by the government to be an industry self-regulator.

Figure 1: PAWG model approach to a distribution pricing methodology



3.4 Overview of PAWG model pricing-setting process

3.4.1 Under the PAWG model approach, the process for setting distribution tariffs follows the basic steps of allocating costs and then setting prices for load profiles. This process is outlined below.

Cost categories

3.4.2 A distributor should first categorise its total target revenue requirement⁸ into the following three components:

- (a) costs incurred by a distributor to provide equipment or services that it would not incur but for the exclusive requirements of a particular consumer (**consumer-specific costs**);
- (b) costs incurred by a distributor to provide network capacity to supply the load on its network (**load-dependent costs**); and
- (c) costs incurred by a distributor to provide distribution services but which are neither directly related to the network capacity nor consumer-specific costs (**load-independent costs**).

Allocating load-dependent costs to asset groups

3.4.3 Distributors should define zones geographically for areas where cost drivers or characteristics differ significantly from those of another area. However, distributors must ensure that, as set out in the GPS, any changes to rural line charges are kept in line with changes to urban line charges.

3.4.4 Distributors should further disaggregate assets within a geographic zone into groups of shared network assets for which the costs may be distinguished from the costs of other groups of shared network assets and may be defined in terms of their location and/or voltage levels (**network asset groups**). This should be done according to the assets' use in delivering electricity to the load groups.

3.4.5 Optimised replacement costs (**ORC**) should be used to allocate load-dependent costs to asset groups. This reflects the LRAIC⁹ of providing distribution services, reduces the variability in costs according to age, and smoothes maintenance cost recovery.

⁸ The setting of this target revenue is outside of the scope of this project; it sits under Part 4 of the Commerce Act.

⁹ The LRAIC is calculated by considering the incremental cost of providing the capacity to distribute to the existing maximum load over the life cycle of the network assets. This calculation involves consideration of the annualised load-dependent costs, generally calculated as the optimised replacement cost of the assets multiplied by an annual capital recovery factor plus the annual operating and maintenance costs.

Allocating network asset group costs to load groups

- 3.4.6 The key cost drivers to be used for allocating network asset group costs to load groups are the load groups:
- (a) after diversity anytime maximum demand (**AMD**); and
 - (b) coincident peak demand (**CPD**).
- 3.4.7 Distributors should categorise load groups into the following connection categories:
- (a) load groups that are supplied from the sub-transmission network (**large major connections**);
 - (b) load groups that are supplied from the 11kV network (**major connections**); and
 - (c) other load groups (**general connections**).
- 3.4.8 Distributors may then disaggregate further the general connections assets into the following load groups:
- (a) up to 15kVA;
 - (b) 16kVA up to 70kVA; and
 - (c) 71kVA or greater.

Price signalling

- 3.4.9 Network congestion should be signalled through dynamic congestion periods and dynamic demand prices, where and when the benefits outweigh the costs.
- 3.4.10 Where it is not cost effective to dynamically signal congestion to consumers (or impractical for consumers to respond to dynamic price signals), distributors should pre-define high price periods approximating congestion periods:
- (a) for winter-peaking networks, standard high price periods of 7am to 11am, and 5pm to 9pm, on winter week days are recommended, although a distributor may define different high price periods and provide reasons for varying from the standard times above; and
 - (b) for summer peaking networks, the distributor should publish the summer season high price periods that it uses to approximate congestion periods.
- 3.4.11 In addition to the above high price periods, distributors may define shoulder periods either side of each high price period.

Model price structure

- 3.4.12 Distributors should recover target revenue from large major, major and general connections with half-hourly metering through:
- (a) fixed prices that recover consumer-specific and load-independent costs;
 - (b) fixed capacity prices based on contracted or agreed capacity (in kVA) at the connection point or the preceding year's peak demands (in kVA); and
 - (c) a variable congestion period price component charged on marginal demand and reflecting the LRAIC.
- 3.4.13 Distributors should recover target revenue from general connections without half-hourly or multi-rate metering through:
- (a) a fixed price component that recovers consumer-specific costs, load-independent costs and, if appropriate, the capacity part of the load dependent costs; and
 - (b) a variable average demand or consumption component using high, shoulder and low prices.

3.5 Distributor business models in New Zealand

- 3.5.1 The PAWG report noted that there exists a fundamental difference in approaches to distribution pricing in New Zealand. Two main business models are currently used by distributors:
- (a) the wholesale delivery model (**WDM**), in which metered quantities reconciled at the GXP are used for calculating distribution prices payable by retailers; and
 - (b) the retail delivery model (**RDM**), in which metered quantities at the ICP are used for calculating distribution prices payable by retailers, or consumers.
- 3.5.2 In practice, neither model¹⁰ is used in its pure form. No distributor charges solely on the GXP metered quantities and even where charging is based entirely on ICP metered quantities, GXP data may be used to derive a residual profile for calculating prices (as in the examples shown in Appendix D of the PAWG report).
- 3.5.3 A distributor's choice of business model affects the extent to which it can disaggregate its costs and set different prices for different load groups across the distribution network.
- 3.5.4 The PAWG report accommodates both business models in its model approach.

¹⁰ The wholesale delivery model is also referred to as a GXP pricing approach, and the retail delivery model as an ICP pricing approach.

4. Summary of regulatory and contractual arrangements

4.1 Introduction

4.1.1 The pricing arrangements of Electricity Lines Businesses (**ELBs**) are regulated under the Commerce Act and, to a lesser extent, the Electricity Act, with the aim of ensuring lines companies do not extract monopoly rents and maintain acceptable levels of quality for end users.

4.1.2 This section summarises the regulatory and contractual arrangements that apply to:

- (a) determine how the revenue requirement is set and monitored (default/customised price path thresholds and information disclosure);
- (b) the allocation of the revenue requirement (including the development of a model approach to a distribution pricing methodology); and
- (c) the contractual arrangements under which any pricing methodology is applied.

4.2 Setting the target revenue requirement

Input methodologies

4.2.1 Part 4 of the Commerce Act provides for the regulation of electricity lines services. Non-consumer-owned ELBs are subject to price-quality regulation and information disclosure, whereas consumer-owned ELBs are only subject to information disclosure. Both these forms of regulation are informed by “input methodologies”.

4.2.2 The Commerce Commission must determine “input methodologies” that apply (in varying degrees) to the inquiries and various regulatory instruments provided for in Part 4 of the Commerce Act.

4.2.3 “Input methodology” is defined in section 52C of the Commerce Act and includes any methodology, process, rule or matter relating to:

- (a) the cost of capital;
- (b) the valuation of assets, including depreciation, and treatment of revaluations;

- (c) the allocation of common costs, including between activities, businesses, consumer classes,¹¹ and geographic areas;
- (d) the treatment of taxation; and
- (e) pricing methodologies.¹²

4.2.4 The relationship between the Commerce Commission's input methodology on pricing methodologies and the work the Commission is doing on distribution pricing needs to be clear. While the Commerce Commission is not bound by the Commission's approach to a distribution pricing methodology, it is required by section 54V(c) of the Commerce Act (and paragraph 5.8(c) of the Memorandum of Understanding between the two Commissions dated November 2008) to take into account any guidelines of which the Commission advises it, that are likely to be relevant to the exercise or performance of its powers, duties or functions. Accordingly, the two Commissions are working together to ensure the two work streams are aligned and clarifying respective roles for the industry.

4.2.5 If an input methodology changes after the new default price-quality paths (due to be reset by 1 April 2010), and if it would have resulted in a materially different path being set, then within 9 months of that input methodology being set, the Commerce Commission may reset the default price-quality path and apply claw-back.¹³

4.2.6 Once the input methodologies have been published, they are applied:¹⁴

- (a) by the Commerce Commission in determining the prices and quality standards applying to electricity lines services of non-consumer owned ELBs; and
- (b) by ELBs in accordance with the relevant determination under section 52P of the Commerce Act. For instance, information disclosure must consistent with the input methodologies specified in the relevant section 52P determination for ELBs.

Price path threshold

4.2.7 On and after 1 April 2009, the thresholds are deemed to be a section 52P determination as if those thresholds were default price-quality paths (**DPP**)¹⁵ —. The Initial DPP is will be reset on 1 April 2010.

¹¹ The terms "consumer classes" and "consumer groups" are used interchangeably.

¹² See also section 52T of the Commerce Act.

¹³ See section 54K of the Commerce Act.

¹⁴ See section 52S of the Commerce Act.

¹⁵ see section 54J(2) of the Commerce Act.

- 4.2.8 The Notice provides that the “notional revenue” of a lines business is not to exceed the “allowable notional revenue” of the lines business (both of which are calculated in accordance with the Notice). In that way, the allowable notional revenue sets the price path for notional revenue.
- 4.2.9 After the Commerce Commission has reset the default price-quality paths for ELBs on 1 April 2010, ELBs may make a proposal for a customised price-quality path.¹⁶

Information disclosure

- 4.2.10 One of the ways the Commerce Commission monitors the performance of ELBs against their regulatory is through information disclosure under the *Electricity Distribution (Information Disclosure) Requirements 2008*.¹⁷
- 4.2.11 Among the matters that ELBs are currently required to publicly disclose are their pricing methodologies. In the future, ELBs will be required to meet any information disclosure requirements determined by the Commerce Commission under section 52P of the Commerce Act. The Commerce Commission is required to determine these as soon as practicable after 1 April 2009.¹⁸

4.3 Allocating the target revenue requirement

- 4.3.1 The allocation of distributors’ revenue is covered by their pricing methodologies. This is relevant to the Commission’s, as well as the Commerce Commission’s functions.

GPS

- 4.3.2 One of the Commission’s functions set out in section 172O of the Electricity Act is to “give effect to GPS objectives and outcomes”. These include the Government’s requirements for distribution pricing methodologies. Paragraph 100 of the 2009 GPS provides:

“The Commission should develop, in consultation with interested parties, principles or model approaches to distribution pricing and monitor their

¹⁶ See section 53L of the Commerce Act. Under section 53Z(1) of the Commerce Act, the Commerce Commission is not required to consider any more than 4 proposals for a customised price-quality path relating to the same type of regulated goods or services in any one year.

¹⁷ See the Commerce Commission’s *Electricity Distribution (Information Disclosure) Requirements 2008* is available at:
[http://www.comcom.govt.nz/IndustryRegulation/Electricity/ElectricityInformationDisclosure/ContentFiles/Documents/Electricity%20Distribution%20\(Information%20Disclosure\)%20Requirements%202008%20-%20%2075765301.pdf](http://www.comcom.govt.nz/IndustryRegulation/Electricity/ElectricityInformationDisclosure/ContentFiles/Documents/Electricity%20Distribution%20(Information%20Disclosure)%20Requirements%202008%20-%20%2075765301.pdf)

¹⁸ See sections 54F and 54I of the Commerce Act.

uptake. The Commission should recommend regulations if required to ensure compliance. As part of this work the Commission should investigate barriers to demand side participation.”

- 4.3.3 The GPS also contains a number of more specific outcomes related to distribution pricing, which are set out in Appendix 1.

Electricity Act

- 4.3.4 Developing a voluntary model approach to distribution pricing also furthers a number of the Commission’s principal objectives and the specific outcomes set out in section 172N of the Electricity Act 1992.

4.4 Distribution agreements with customers

- 4.4.1 Distribution agreements regulate the delivery of electricity lines services by a distributor to a consumer’s point of connection on the network. These arrangements can be either directly between the distributor and the consumer, or via a retailer. A number of different forms of agreement are used, including model use of system agreements developed by the Commission.

- 4.4.2 The basis on which a distributor charges the users of the distribution network under any of the arrangements discussed below is set out in that distributor’s distribution pricing methodology.

Model use of system agreements

- 4.4.3 The Commission has developed model distribution use of system agreements for both interposed and conveyance distribution options. Both model agreements cover commitments, payment obligations, operational requirements and the rights of each party.
- 4.4.4 The interposed model use of system agreement is used in situations where the contractual relationship between the distributor and the consumer is via the retailer. The retailer acts as the consumer’s agent for the procurement of distribution lines services (and therefore indirectly transmission lines services).
- 4.4.5 Under a conveyance use of system agreement, the distributor has a direct contractual relationship with the consumer for the provision of lines services and a separate agreement with the retailer for the conveyance of electricity across the distribution network. The consumer and retailer then have a further agreement for the provision of retail services.

4.5 Other legislation potentially affecting pricing methodologies

4.5.1 The Commission has considered what other legislation potentially affects the development of a voluntary model approach. Relevant current and proposed legislation includes:

- (a) the Electricity (Continuance of Supply) Amendment Bill (currently before the Commerce Select Committee, with a report due on 30 June 2009), under which regulations may be made that require suppliers of electricity by alternative means to use a specified pricing methodology in setting the price for that electricity;
- (b) the Low Fixed Charge Regulations, which influence distribution tariffs by outlining the way in which distributors are to charge in respect of homes on low fixed charge tariff options, so as to assist retailers to deliver low fixed charge tariff options; and
- (c) the DG Regulations, which set out the basis on which distributed generation is connected to a distribution network, including processes and timeframes by which generators may apply to distributors for approval to connect distributed generation, a process to be followed if approval is granted, regulated terms applicable to the connection of distributed generation in the absence of contractually-agreed terms, a default dispute resolution process, and pricing principles.

5. Guiding principles for the proposed model approach

5.1 Introduction

5.1.1 To guide the development of the proposed model approach, the Commission has developed a set of guiding principles. These build on the guiding principles used by the PAWG, reflect the Commission's objectives and required outcomes as set out in the Act, and take into account the GPS.

5.2 Commission objectives and required outcomes

Electricity Act

5.2.1 Under section 172N of the Act, the Commission is required to:

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

5.2.2 Consistent with those objectives, the specific outcomes the Commission must seek to achieve include that:

- (a) energy and other resources are used efficiently;
- (b) barriers to competition in electricity are minimised for the long-term benefit of end-users;
- (c) incentives for investment in lines, energy efficiency, and demand-side management are maintained or enhanced;
- (d) the full costs of producing and transporting each additional unit of electricity are signalled; and
- (e) delivered electricity costs and prices are subject to sustained downward pressure.

Government Policy Statement

5.2.3 As discussed above, one of the Commission's functions is to give effect to GPS objectives and outcomes, which include the government's requirements for distribution pricing methodologies, as set out in paragraphs 100, 101 and 102 of the GPS:

“Distribution pricing methodologies

100. The Commission should develop, in consultation with interested parties, principles or model approaches to distribution pricing and monitor their uptake. The Commission should recommend regulations if required to ensure compliance. As part of this work the Commission should investigate barriers to demand side participation.

101. The diversity and complexity of the terms and conditions offered by different lines companies for use of their lines is often cited as a significant barrier to expansion of retail competition. The Commission should consider whether standardisation and simplification of tariff schedules and contractual arrangements would facilitate market entry by retailers.

102. The Government expects distribution companies to keep any changes to rural line charges in line with changes to urban line charges. The Commission should monitor developments in rural charges”.

5.2.4 In addition, there are a number of outcomes that the government has included in the GPS that are relevant to developing the proposed model approach, including the following:

- (a) Whenever possible, the Commission should use its powers of persuasion and promotion, and provision of information, guidelines and model arrangements, to achieve its objectives rather than recommending regulations and rules. The Commission should monitor compliance with these guidelines and model arrangements and recommend regulations or rules if voluntary arrangements prove unsatisfactory (paragraph 2).
- (b) The Commission should promote pricing structures that provide appropriate signals to manage transmission and distribution losses and constraints (paragraph 63).
- (c) The Commission should promote and facilitate the efficient use of electricity by end users in multiple and mutually-reinforcing ways, including:
 - (i) by promoting cost-reflective pricing;
 - (ii) by seeking innovative ways to enable residential and other consumers to respond to pricing incentives to use electricity more efficiently;
 - (iii) by encouraging and facilitating demand-side participation in the wholesale, distribution and retail markets; and
 - (iv) by promoting the efficient use of load management (paragraph 64).
- (d) The Commission should have regard to any provision by the Commerce Commission requiring distributors to engage with local communities on the

trade-offs they wish to make concerning price, quality and reliability of supply (paragraph 40).

- (e) Undue barriers to investment in renewable electrical energy should be reduced or removed and efficient uptake of renewable generation should be promoted (paragraph 66).
- (f) interacting with the Commerce Commission (through the Memorandum of Understanding between the two commissions) to improve incentives for distributors in respect of:
 - (i) managing distribution losses;
 - (ii) facilitating uptake of advanced metering infrastructure and more efficient distribution pricing;
 - (iii) ensuring target security levels for distribution networks are met at least cost; and
 - (iv) facilitating investment in energy efficiency (including consumer end-use efficiency), demand side management and distributed generation (paragraph 109).

5.3 PAWG guiding principles

5.3.1 In developing the PAWG model approach, the PAWG adopted the guiding principles for distribution pricing previously developed by the Model Distribution Arrangements Project, which was established under the Metering and Reconciliation Information Agreement.

5.3.2 These guiding principles for distribution pricing were as follows:

- (a) prices should encourage efficient investment and technology innovation in the provision of distribution services;
- (b) prices should not create inefficient barriers to entry in the market for distribution services;
- (c) prices should not unjustifiably discriminate between retailers/consumers of the distributor;
- (d) prices should encourage the efficient use of distribution services;
- (e) prices should, so far as it is efficient to do so, relate to the level of service delivered and reflect the cost structures and risks of delivering the services, and be easily understood;
- (f) changes to pricing methodology (and the rationale for them) should follow consultation with interested parties, and be widely publicised, transparent, predictable and readily verifiable; and

- (g) prices should satisfy legal and regulatory requirements.

5.4 Discussion

- 5.4.1 Although they form a useful starting point, expansion and further elaboration of the PAWG guiding principles are required in order to adequately capture the Commission's objectives and specific outcomes in respect of distribution pricing.
- 5.4.2 A key area to be considered while developing the distribution pricing guiding principles is improving economic incentives in respect of:
 - (a) efficient investment in energy efficiency, demand-side management and distributed generation;
 - (b) the uptake of AMI and more efficient distribution pricing; and
 - (c) ensuring target security levels for distribution networks are met at least cost.
- 5.4.3 Another key area where the PAWG guiding principles require expanding is the promotion of pricing structures that provide appropriate signals to manage losses and constraints. Included in any discussion about losses must also be consideration of unaccounted for electricity (**UFE**), which has become much more transparent in the period since the PAWG methodology was published, via the introduction of global reconciliation in the wholesale electricity market.
- 5.4.4 The distribution pricing guiding principles should also address the trade-off between facilitating more efficient distribution pricing and the standardisation and simplification of distribution tariff schedules. The Commission considers that the proposed model approach balances this trade-off. The Commission is also concerned to ensure that distribution pricing does not create a barrier to the expansion and enhancement of retail competition in New Zealand.
- 5.4.5 The PAWG guiding principles should also be extended to specify that a pricing methodology should recover costs in a manner that avoids volatility and unpredictability in price levels and in distributors' revenue, so as to reduce costs to consumers and distributors that arise from economic uncertainty.
- 5.4.6 The Commission's objectives and specific outcomes in respect of investment in renewable energy have also been considered in developing the proposed guiding principles.

5.5 Proposed guiding principles

- 5.5.1 The Commission's proposed guiding principles for the proposed model approach are as follows:

- (a) A distribution pricing methodology should:
 - (i) encourage the efficient and fair allocation of costs, avoiding cross-subsidisation and unfair discrimination;
 - (ii) be stable and predictable in respect of revenue for the distributor and charges to consumers; and
 - (iii) be practicable to implement, without placing significant transaction costs on consumers and distributors.
- (b) Changes to a distribution pricing methodology (and the rationale for them) should be widely publicised and follow consultation with interested parties. The revised distribution pricing methodology should be transparent, with the results predictable and readily verifiable.
- (c) Distribution prices should:
 - (i) encourage the efficient use of electricity distribution services;
 - (ii) encourage efficient investment in distribution, transmission, distributed generation (including renewable generation), and technology innovation (including AMI);
 - (iii) not create barriers for retail competition and the provision of distribution or other services;
 - (iv) provide appropriate signals to manage transmission and distribution losses and constraints;
 - (v) relate to the quality and reliability of service delivered, including the risks of delivery; and
 - (vi) be easily understood.

5.5.2 The Commission is seeking input on the proposed guiding principles.

Q1. Do you agree with the content of these proposed guiding principles? Are there alternative or additional guiding principles that should be considered?

6. Distributor business models

6.1 Introduction

6.1.1 The PAWG report refers to two alternative business models that New Zealand distributors use to charge for distribution services:

- (a) the RDM (retail delivery model); and
- (b) the WDM (wholesale delivery model).

6.1.2 This section discusses the key merits of each of the RDM and WDM. The discussion is limited to consideration of distribution pricing and therefore ignores any retail pricing considerations, such as rebundling of distribution tariffs by retailers under the RDM and unbundling of distribution tariffs by retailers under the WDM, except to consider the cost implications involved in bundling and unbundling.

6.2 Retail delivery model (RDM)

6.2.1 Under the RDM, distributors use metered or estimated consumption quantities at individual ICPs to calculate distribution charges. Each ICP can then be allocated to a load group, consumer class, service level, and network area (see Figure 2).

6.2.2 Retailers with interposed use of system agreements are charged for all distribution services at the ICP level. They then combine these charges with their energy-related costs to produce a retail price for delivered energy to the end-use consumer. The distributors' charging regime under the RDM is commonly referred to as ICP pricing.

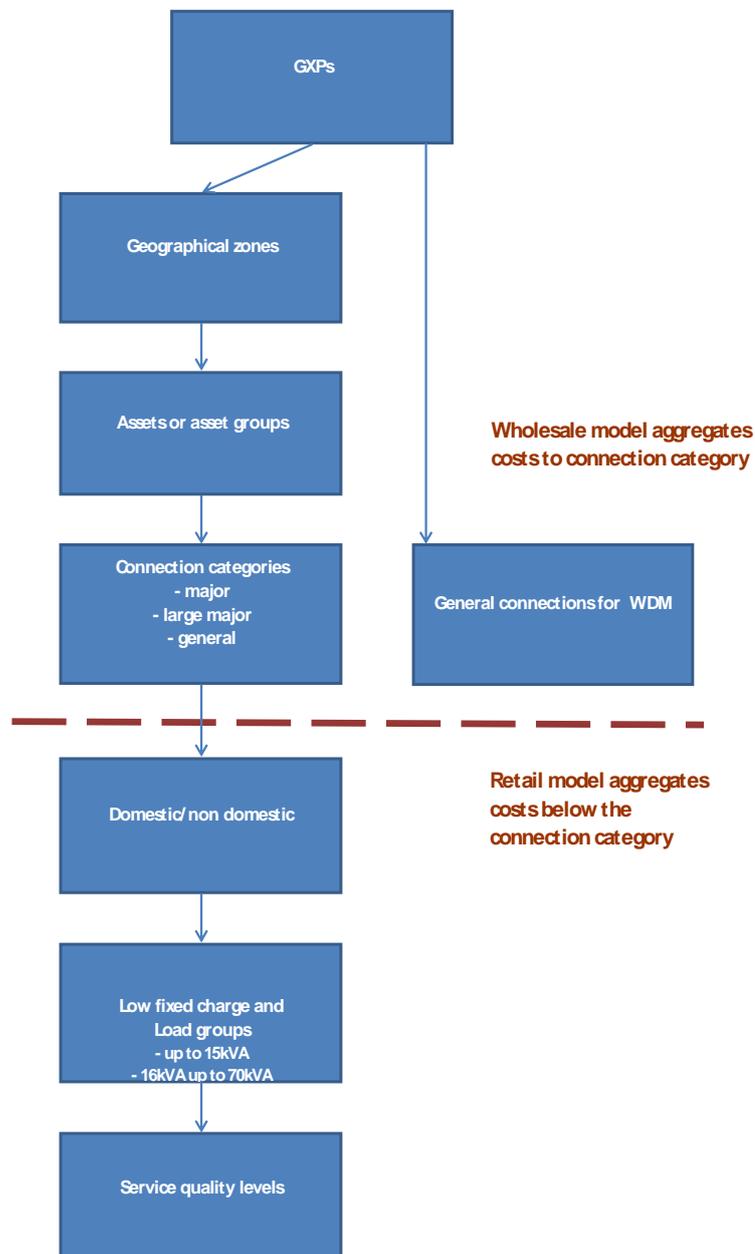
6.3 Wholesale delivery model (WDM)

6.3.1 Under the WDM, distributors allocate costs for general connection consumers to retailers on the basis of reconciled metered quantities at a GXP (see Figure 2). Hence this form of pricing is commonly referred to as GXP pricing.

6.3.2 Under a pure WDM, all distribution costs would be allocated on the basis of reconciled GXP metering data. However, this would not capture consumer-specific costs for major and large major load groups. Hence, the Commission understands that all distributors that use the WDM do so only for general connection consumers, with consumers in the major and large major load group classifications having their distribution charges calculated using the RDM.

- 6.3.3 The reconciliation process enables the purchase of electricity at each GXP by identifying the half-hourly demand of each purchaser. For those quantities that have not been obtained using half-hourly metering or have not been submitted with profiles, purchasers submit aggregate quantities for which the reconciliation process develops a residual profile, which enables the half-hourly demands to be calculated. Most general connection consumers do not have half-hourly metering.
- 6.3.4 Combining the reconciled aggregated demand for general connection consumers with the individually-metered demands for major and large major consumers for each retailer enables a distributor to identify each retailer's contribution to the maximum demand at a GXP on the distribution network in any half-hour time period.

Figure 2: WDM and RDM allocation of load dependent costs



6.4 Use of each business model in New Zealand

6.4.1 The majority of distributors allocate and recover costs for all consumers on their networks using the RDM.

6.4.2 The distributors that use the RDM for allocating and recovering costs for major and large major load group consumers, and the WDM for the allocation of costs for the remaining general connections, are:

- Alpine;
- Network Waitaki;
- Orion;
- Otago Net;
- Powerco (Western area);
- Powernet; and
- ScanPower.

6.5 Pricing signals

6.5.1 Both the RDM and WDM can be used by a distributor to send a price signal relating to contribution to network peak demand during periods when the network is capacity constrained. For general connection consumer load, under the WDM this signal is conveyed to retailers, at the GXP level. Under the RDM, congestion prices are able to be signalled at the ICP level for all load groups. Currently, this could be achieved via the use of ripple control to:

- (a) switch registers in a meter or to switch between two meters, for time of use pricing (**TOU pricing**); or
- (b) control the load in instances where there is a single meter with a single register and a ripple control relay is installed at the premises, for controlled load pricing;

or a combination of the above, whereby two ripple relays are used to:

- (i) switch between meter registers; and
- (ii) control load.

6.5.2 In future, AMI may enable more sophisticated signalling of prices and congestion periods at the ICP level for all load groups.

6.5.3 In a competitive market, the extent to which retailers will be incentivised to react to a congestion signal will depend on the extent to which it benefits their

competitive position in the market. In a network with WDM, retailers with low market share can have more incentive to remove load control, thereby avoiding any potential inconvenience to their customers, than to offer it. This is due to the public good nature of load control.

- 6.5.4 Without the use of a controlled load profile on a WDM network, any savings achieved through a reduction in the demand at one general connection ICP are usually shared across all retailers in that area of the network based on market share.
- 6.5.5 Consequently, the benefits of load control investment are skewed towards the high market share retailers. All else being equal, a small retailer with a 10% market share stands to lose 90% of the benefit from its reduction in peak demand, if it does not have a controlled load profile. Any retailer may construct and use a profile, and a number of retailers (but not all retailers) have controlled load profile shapes that are used in the reconciliation process on WDM networks. Consequently, the effect of controlled load is taken into account in their wholesale market purchases and line charge settlements.
- 6.5.6 The fact that not all retailers have chosen to use controlled load profiles, and the impact of the shared benefits of controlled load, provide an incentive for some retailers to reduce their costs¹⁹ and improve services to their consumers by removing any installed ripple control relays at their customers' premises.
- 6.5.7 The incentive for retailers to remove load control equipment for pricing purposes will reduce the load available for control during system emergencies. One distributor using GXP pricing (Orion²⁰) has made it compulsory for load control relays to be installed at each ICP, for emergency load management. Another distributor (Alpine Energy²¹) has introduced a hefty penalty (\$229.45 per annum) for installations with uncontrolled water heating. With respect to the signalling of other types of network costs, such as those driven by geographic location or load group, the WDM is inferior to the RDM because it does not provide price signals at a sufficiently disaggregated level. Under the WDM, there is a greater potential for cross-subsidisation of network costs between general connection consumers than under the RDM.

¹⁹ For example, paying a fee for use of the ripple relay.

²⁰ See <http://www.oriongroup.co.nz/downloads/Ripple%20relays%20for%20water%20heating.pdf>

²¹ See <http://www.alpineenergy.co.nz/LineCharges2009.pdf>

6.6 Management of losses

- 6.6.1 The quantity of electricity measured at ICPs is less than the quantity measured at the GXP from which the ICPs are supplied, due to technical and non-technical losses on the distribution network.
- 6.6.2 Technical losses are due mainly to the heat generated in conductors and transformers. They are influenced by the design and configuration of the network, conductor sizes and lengths, and the distribution network voltage.
- 6.6.3 Non-technical losses arise primarily from the theft of electricity, failure to read all meters, metering inaccuracies, inaccurate estimates of unmetered electricity, and inaccurate profiles.
- 6.6.4 Distributors can influence the level of technical and non-technical losses, as they control the design, configuration and equipment used on their networks and can have a complete view of all ICPs. However, distributors do not have direct access to meter reading and data handling processes within retailer organisations and do not have control over non-technical losses. The revenue that distributors earn using the RDM is affected by the level of these non-technical losses and they can compensate for this by adjusting total loss factors for their networks, or by taking steps to identify and reduce the causes of non-technical losses.
- 6.6.5 Distributors determine their loss factors based on the expected total losses on the network, and these are applied to the metered quantities at each ICP to enable the GXP quantities to be calculated²². Any difference between the loss-adjusted quantities and the metered quantities at a GXP results in unaccounted for electricity (**UFE**). Under the wholesale market settlement arrangements, UFE is shared amongst the retailers trading at each GXP in proportion to their market share.
- 6.6.6 By using the WDM, a distributor avoids any short-term risk²³ of its revenue being adversely affected by an increase in technical and/or non-technical losses (as loss factors are re-calculated annually). In contrast, a distributor which charges at the ICP faces the short-term risk that the billed quantities of electricity at the ICP are in fact lower than the delivered quantities. By recalculating loss factors annually, the distributor can adjust its prices to compensate for trends in non-technical losses.

²² Refer to the "Guidelines on the calculation and the use of loss factors for reconciliation purposes Version 2.0 18 September 2008"

²³ The annual recalculation of losses in the above guideline means that any risk is short term only before it is recalculated into price.

- 6.6.7 Distributors using the WDM or RDM therefore have low incentives to manage and, if possible, reduce total losses, and the cost of these losses in both instances is passed to the retailer and eventually to the consumer. However, distributors using RDM cannot completely recover lost revenue in instances where losses are greater than expected, and hence there are examples of these distributors taking steps to reduce non-technical losses. Such examples include:
- (a) Vector²⁴ undertook a comprehensive review of ICPs in its original network to identify unread meters, so as to reduce the impact of the unread quantities on its revenue; and
 - (b) Buller Electricity²⁵ undertook an analysis of retailer billing data and reconciled electricity quantities to identify the causes of data discrepancies that were having an impact on non-technical losses and consequently on its revenue.
- 6.6.8 As noted above, the distribution pricing methodology provides distributors with low incentives to invest in reducing losses. Distributors will tend to accommodate losses that they cannot control by building the cost into their prices or by employing the WDM to reduce their risk. The RDM does however place a greater incentive on distributors to minimise losses than does the WDM, because there is a short term revenue risk for distributors.
- 6.6.9 Using the PAWG approach, both the RDM and the WDM could provide pricing signals that would influence the level of losses at high usage periods but the transmission of these signals to end users depends on the retailer's pricing methodology and that lies outside the scope of this review.

6.7 Costs

- 6.7.1 Under the WDM, distributors avoid certain costs by leaving the retailer to carry out functions that would otherwise be required of the distributor under the RDM. Costs that are avoided by distributors and transferred to retailers under the WDM include:
- (a) higher administration costs, including the costs of developing more detailed pricing structures;
 - (b) additional information management costs – for example, of consumer databases; and
 - (c) consumer communications and relationship management costs.

²⁴ Vector supplies distribution services directly to consumers in the area of Auckland south of the harbour bridge and uses retailers to recover the revenue through their billing systems.

²⁵ See <http://www.electricitycommission.govt.nz/pdfs/advisorygroups/pjtteam/reconproject/forum-Jul08/Presentations-recon-buller.pdf>

6.7.2 In New Zealand, where there are significantly more distributors than retailers, and a number of distributors are small organisations, the transfer of these costs could lead to overall efficiency gains across the industry because of retailers having economies of scale in undertaking these functions.

6.8 Other jurisdictions

6.8.1 The WDM for distribution pricing appears to be unique to New Zealand. In other countries with similar institutional arrangements to New Zealand, i.e. the UK and Australia, distributors' pricing methodologies are based on cost allocation to the lowest load group or consumer class, and pricing to retailers occurs at the consumer premises level.

6.9 Discussion and comparison against guiding principles

6.9.1 The WDM is simpler and lower cost for distributors to administer than the RDM. In instances where load supplied from a GXP is uniform across an unconstrained network, the WDM achieves the same pricing outcome as the RDM, at lower cost.

6.9.2 In the WDM, the general connections for each retailer can be considered as a single connection with half-hourly metering. Conceptually, this makes the retailer comparable to a single major or large major consumer or an embedded network. However, whereas the distributor is charging for its service at the point of connection for major and large major consumers and embedded networks, for general connections the distributor is charging for its service at the GXP. This means that an individual general connection (via its agent, the retailer) is not receiving from the distributor an individualised cost for the distributor's services. The retailer receives a single invoice for its aggregated general connection usage of distribution services. Such an approach reduces transparency in an end user's distribution costs, and is more likely to reduce the equitable and fair allocation of costs between individual end users.

6.9.3 In contrast to the WDM, the RDM is more complex and costly to administer for distributors and may require additional metering for controlled load on consumers' premises. A key issue with the RDM is the accuracy of the ICP information held in databases (distributor, retailer and the registry).

6.9.4 However, the RDM provides more accurate pricing signals to individual ICPs than does the WDM because the costs may be differentiated by consumer class (e.g. domestic or non-domestic). The RDM can differentiate not only in respect of the quantity of supply to individual ICPs, but also the quality of service. As

incremental network costs can be orders of magnitude higher than energy costs, any misallocation of distribution costs to load groups can have a significantly higher impact than say, the misallocation of energy.

- 6.9.5 The RDM also places a stronger incentive on distributors to minimise the burden on consumers from non-technical losses than does the WDM. The WDM shifts all of the financial risk associated with total losses to retailers, even though distributors are in a better position to influence technical losses and can take measures to reduce non-technical losses (e.g. ensuring that all connection points have a retailer supplying them).
- 6.9.6 The introduction of AMI in New Zealand is occurring and a number of retailers have announced target dates for the installation of more than 1.5 million meters by 2013²⁶. This development has the potential to improve the quality of data available at the ICP level and provides an opportunity for distribution pricing to be applied on a TOU basis at those ICPs with AMI.
- 6.9.7 AMI will enable the PAWG recommendations on pricing for general connection consumers to be implemented more easily, as general connections will have the capability to store data on usage at different times of the day, week or year.
- 6.9.8 Over time, improving the capability of AMI will enable more general connection consumers to move into the category of electricity consumer with half-hourly metering, and thereby offer distributors the opportunity to collect data on the usage and quality of supply at the ICP level. This will enable the allocation of distribution costs on the basis of demand measured at the ICP level, and will provide the opportunity to reward individual consumers (through their retailer) for load shifting or load reduction in response to price signals. It may also assist in measuring quality of service and the development of service differentiation for distribution cost allocation and pricing purposes.
- 6.9.9 Table 1 provides a summary comparison²⁷ of each of the RDM and WDM against the guiding principles for a model approach to a distribution pricing methodology, put forward in section 5.

²⁶ Report to the Parliamentary Commissioner for the Environment by Strata Energy Ltd "*International experience with smart meters (energy)*" dated May 2008.

²⁷ These comparisons are based on an interposed use of system agreement between a distributor and a retailer. In that situation the distributor passes its pricing signals through the retailer who may bundle or unbundle the charges to suit its pricing plans for delivered electricity. Where a conveyance agreement is used the pricing signals are passed directly to the consumer.

Table 1: Business model comparison against guiding principles

Guiding principle	WDM	RDM
A distribution pricing methodology should:		
encourage the efficient and fair allocation of costs, avoiding cross-subsidisation and unfair discrimination	Because costs are allocated at the GXP level, the WDM is more likely to lead to cross-subsidisation of costs between general connections than the RDM	Costs can be differentiated by consumer class, geographic zones and by service level, thereby reducing cross-subsidisation between general connections
be stable and predictable in respect of revenue for the distributor and charges to consumers	Provides predictable revenue for the distributor. However, reconciliation and congestion charge wash-ups can cause unpredictable charges for retailers who may or may not be able to recover these from consumers	Is less predictable than the WDM in respect of distributor revenue as distributors may over- or under-recover their revenue requirement
be practicable to implement without placing significant transaction costs on consumers and distributors	Is easier for distributors to implement than is the RDM. Assuming price signal changes are managed, then there should be little if any adverse effect on consumers	Is more difficult for distributors to implement than the WDM. Assuming price signal changes are managed, then there should be little if any adverse effect on consumers
Changes to a distribution pricing methodology (and the rationale for them) should be widely publicised and follow consultation with interested parties. The revised distribution pricing methodology should be transparent, with the results predictable and readily verifiable	Because of the aggregation of costs inherent in the WDM, a revised methodology may still not result in transparent and readily verifiable pricing at the general connection end user level	Because of the disaggregation of costs inherent in the RDM, a revised methodology should still result in transparent and readily verifiable pricing at the general connection end user level (due to the requirements of the Electricity Distribution (Information Disclosure) Requirements 2008)

Guiding principle	WDM	RDM
Distribution prices should:		
encourage the efficient use of electricity distribution services	Because costs are allocated at the GXP level, the WDM is not as cost-reflective at the general connection end user's point of connection as is the RDM, and therefore the WDM tends not to encourage them to use electricity as efficiently as does the RDM	Because costs are allocated at the ICP level, the RDM tends to be more cost-reflective at the end user's point of connection than does the WDM, and therefore the RDM tends to encourage them to use electricity more efficiently than does the WDM
encourage efficient investment in distribution, transmission, distributed generation (including renewable generation), and technology innovation	<p>If distribution prices at the GXP level are not passed through to end users fully, then the failure to signal distribution prices at the ICP level can lead to inefficient investment in distribution and potentially transmission to accommodate load peaks on the network</p> <p>By not passing price signals on to general connection end users' points of connection, it could be argued that the WDM encourages certain technology innovation (i.e. AMI, on the proviso that RDM is used for AMI connections)</p>	<p>Signalling distribution prices at the ICP level can encourage efficient investment in distribution and potentially transmission to reduce peaks on the network</p> <p>A desire to improve the accuracy of the RDM can lead to technology innovation (i.e. AMI), as can pricing at the ICP level (i.e. load control)</p>
not create barriers for retail competition and the provision of distribution or other services	Adoption of the WDM does not appear to create a barrier to the expansion of retail competition, or the provision of distribution or other services	Adoption of a <i>common</i> RDM across distributors does not appear to create a barrier to the expansion of retail competition, or the provision of distribution or other services

Guiding principle	WDM	RDM
provide appropriate signals to manage transmission and distribution losses and constraints	The WDM provides appropriate signals to <i>retailers</i> at grid exit points to manage transmission and distribution losses and constraints	The RDM provides appropriate signals to <i>retailers</i> and <i>end users</i> at end users' points of connection to manage transmission and distribution losses and constraints
relate to the quality and reliability of service delivered, including the risks of delivery	<p>The cost structures are at a high level but can be reflected in the retail pricing if the retailer restructures</p> <p>Risks of delivery, in the form of network losses and constraints, are passed on by the distributor to consumers (via their agent, the retailer)</p>	<p>Costs can be disaggregated to reflect service level differences across a distribution network</p> <p>Risks of delivery, in the form of network losses and constraints, are shared by the distributor and consumers thereby providing at least a short-term incentive for the distributor to minimise losses</p>
be easily understood	Under the WDM it is not possible for general connection consumers to understand how their individual distribution charge is determined because of the aggregated basis on which the distributor invoices the consumer's agent, the retailer, unless the retailer as the calculating party makes this information available	Under the RDM it is possible for general connection consumers to see on the distributor's website how their individual distribution charge is determined

6.10 Conclusion

6.10.1 In a number of areas, both the WDM and the RDM appear to meet the guiding principles to a similar extent (e.g. not creating barriers to retail competition and the provision of distribution or other services; providing appropriate signals to manage transmission and distribution losses and constraints; technology innovation). In respect of the other guiding principles the WDM is superior to the RDM for some (e.g. ease of implementation; predictability of revenue for distributors), while the reverse holds for others (e.g. encouraging the efficient and

fair allocation of costs and avoiding cross-subsidisation; being transparent, predictable and readily verifiable).

6.10.2 It is the Commission's view that, overall, the actual and potential benefits of the RDM align it more closely with the proposed guiding principles than do the actual and potential benefits of the WDM. Hence, the Commission proposes that the RDM is incorporated into the Commission's proposed model approach.

6.10.3 Although the WDM is less expensive for distributors to administer and removes revenue risk for them, the RDM more accurately tailors distribution tariffs to reflect an individual consumer's contribution to distribution costs, not only in respect of the quantity of supply but also the quality of service. Providing distribution prices to end users that are cost-reflective encourages the efficient use of electricity. The RDM is also more transparent²⁸ than the WDM (as the retailer, which calculates the line charges, under the WDM, is not required to disclose this information), and provides at least a short-term incentive for distributors to minimise losses. For these reasons, the Commission believes that it is appropriate for the RDM to be used across general connection consumers, in addition to consumers in the major and large major connection categories.

6.10.4 While proponents of the WDM argue that it provides retailers with greater flexibility in the setting of retail prices than does the RDM, strictly speaking this is a retail pricing issue rather than a distribution pricing issue. However, it is noted here that retailers have the same ability to rebundle distribution tariffs to modify pricing signals under the RDM as under the WDM, as there is no requirement for retailers to pass through distribution prices in the form set out by the distributor. However, such re-aggregation will impose an additional cost on retailers compared with the WDM where it is not necessary, which may tend to discourage rebundling.

6.10.5 While it is concluded that the RDM meets the proposed guiding principles more closely than the WDM, both have their merits and both are totally dependent (for interposed arrangements) on the effectiveness of their pricing signals being passed on to end users by retailers.

6.11 Proposal

6.11.1 The Commission proposes a preference for the RDM in the proposed model approach.

Q2. Do you agree that the RDM should be the preferred approach?

²⁸ Even if a retailer rebundles its use of system charges, consumers can generally find the cost of distribution services at the ICP level by referring to the distributor's website.

7. Distribution pricing model

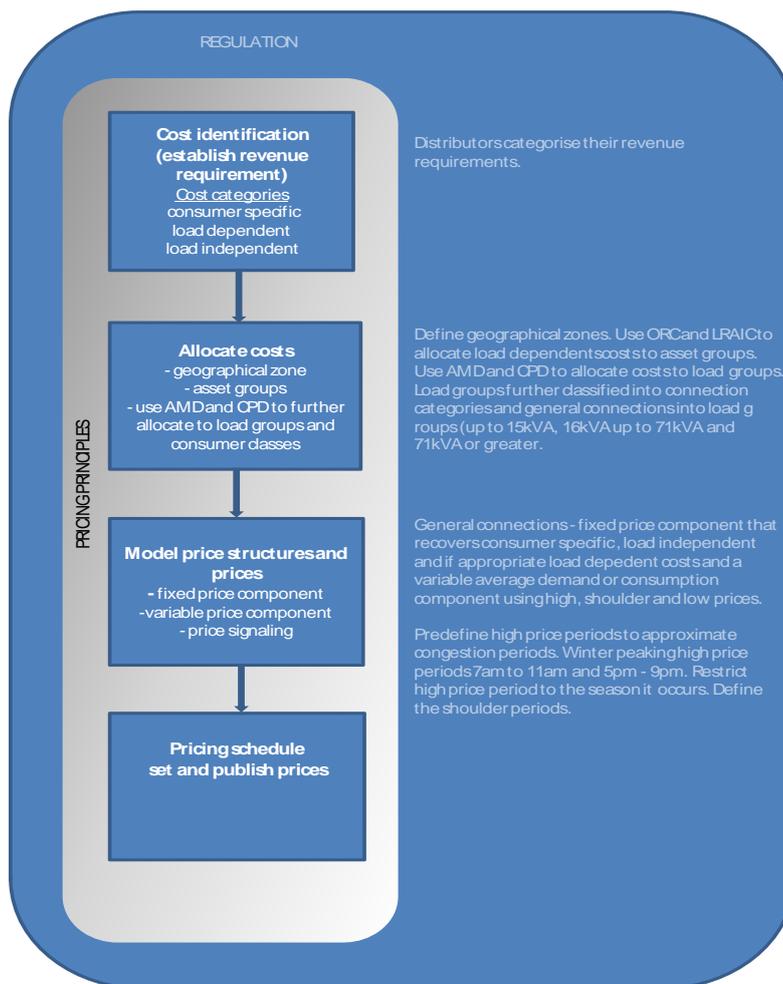
7.1 Approach

7.1.1 The Commission proposes to use the PAWG model approach to distribution pricing, with the addition of the following areas:

- (a) transmission cost allocation;
- (b) distributed generation cost allocation;
- (c) controllable load cost allocation;
- (d) identification of consumer classes within load groups; and
- (e) disaggregation by service quality.

7.1.2 The proposed model approach is summarised in Figure 3 below.

Figure 3: Distribution pricing methodology



7.1.3 The model approach to a distribution pricing methodology consists of four key stages:

- (a) cost categorisation;
- (b) cost allocation;
- (c) model pricing signalling; and
- (d) model price structure.

8. Cost categorisation

8.1 Introduction

8.1.1 The PAWG report recommended breaking down a distributor's total revenue requirement into the following three cost categories:

- (a) consumer-specific costs;
- (b) load-dependent costs; and
- (c) load-independent costs.

8.2 Consumer-specific costs

8.2.1 Where costs can be identified as being specific to an individual consumer, such as dedicated equipment installed or services provided, those costs should be directly recovered from the consumer. Dedicated services are consumer-specific services that are additional to the services normally supplied to all consumers on the network.

8.3 Load-dependent costs

8.3.1 Investment in the distribution network is driven by the need to supply the demand for electricity at a certain level of security and reliability, which are determined by good industry practice.

8.3.2 The cost of operating and maintaining the shared distribution network assets together with interest, depreciation and a reasonable rate of return, define the load-dependent costs that are allocated among the consumers who use the distribution network. The load-dependent costs requirement will depend on the sunk costs and any anticipated reinforcement of the network over the period for which prices apply, as well as the valuation method that is employed for allocating the costs of the assets.

8.3.3 It should be noted that these costs are incurred to meet expected demand and do not necessarily vary in direct proportion with load. Investments in distribution assets are lumpy and at any particular time the need for investment will depend on the available capacity to meet expected demand.

8.3.4 In order to distribute electricity, the network has to be connected to the transmission grid or to another source of electricity. The charges imposed by Transpower through its transmission pricing methodology should be seen as load-dependent costs and thus allocated to the consumers using the network.

8.4 Load-independent costs

- 8.4.1 Where the level of the revenue requirement is regulated, the load-independent costs will be the remainder after the load-dependent costs and consumer-specific costs are deducted from the total revenue requirement.
- 8.4.2 Essentially, these costs are the costs of non-network assets and include the costs of business administration, system operations, depreciation and return on IT and other non-network assets, and regulatory compliance costs and levies.

8.5 Generation-specific costs

- 8.5.1 Categorising a distributor's revenue requirement using the three cost categories identified above, as recommended in the PAWG report, is supported by the Commission.
- 8.5.2 However, the increasing prevalence of distributed generation on distribution networks and the Government's wish to encourage and regulate this trend has led to the promulgation of the DG Regulations.
- 8.5.3 As noted earlier in this consultation paper, the DG regulations set out the way in which distributed generators should be charged or rewarded for their connection to the distribution network.
- 8.5.4 The Commission believes that, due to their nature, "generation-specific costs" should be explicitly considered in any model approach to a distribution pricing methodology and therefore proposes that an additional cost category of "generation-specific costs" should be included in the cost categorisation stage.

9. Cost Allocation

9.1 Introduction

9.1.1 Following the categorisation of costs into consumer-specific, generation-specific, load-dependent and load-independent costs, the second key stage of the proposed model approach is to allocate the costs within each of these categories to the end user level.

9.2 Allocation method

9.2.1 As noted above, the Commission is basing the proposed model approach on the PAWG model approach, with some additions. With respect to cost allocation, the Commission is including the following areas which are additional to those set out in the PAWG model approach:

- (a) transmission cost allocation;
- (b) distributed generation cost allocation;
- (c) controllable load cost allocation;
- (d) identification of consumer classes within load groups; and
- (e) disaggregation by service quality.

9.3 Allocate consumer-specific costs

9.3.1 Consumer-specific costs should be recovered directly from individual consumers.

9.4 Allocate generation-specific costs

9.4.1 Generation-dependent costs should be recovered directly from individual generators in line with the DG Regulations.

9.4.2 Where generators contract for deferral of network investment, they should enter into network support contracts and the allocation of costs and savings should be included in the terms of those contracts (see paragraph 9.7).

Allocating distributed generation costs and benefits

9.4.3 Generation that is directly connected to a distribution network, connected to an embedded network, or installed within a customer network, will influence a distributor's costs. Such generation may increase a distributor's costs due to a

need to reinforce the local network to allow for export of power or increased fault levels, or it may reduce costs by deferring the need to reinforce the local network by reducing demand on the system. Distributed generation may also reduce transmission charges by reducing the network's regional coincident peak demand and by contributing to deferral of transmission upgrading.

- 9.4.4 The Commission queries whether any residual costs and benefits remain to be allocated after a distributor applies the DG Regulations. If this is the case, the Commission queries whether these should be included in the proposed model approach. The key consideration for the Commission on whether residual distributed generation costs and benefits are included is the materiality of any cross-subsidisation that will otherwise occur between load and generation and/or between generators.

9.5 Allocate load-dependent costs

- 9.5.1 The model load-dependent cost allocation process proposed by the Commission is summarised in Figure 4 below. This model sets out to encourage efficient use of assets and the fair allocation of costs to avoid cross-subsidisation and/or discrimination.

Allocating load-dependent costs to network asset groups

- 9.5.2 Once distributors have identified their load-dependent costs, it is proposed that distributors should disaggregate networks into geographic zones where cost drivers or characteristics differ significantly from those of another area.
- 9.5.3 Distributors should then further disaggregate assets within a geographic zone into asset groups according to their voltage level, so as to identify which load groups use them. This is to avoid the allocation of lower voltage asset costs to higher voltage consumers who do not use such assets. This is shown in Table 2.

Figure 4: Allocation of load-dependent costs

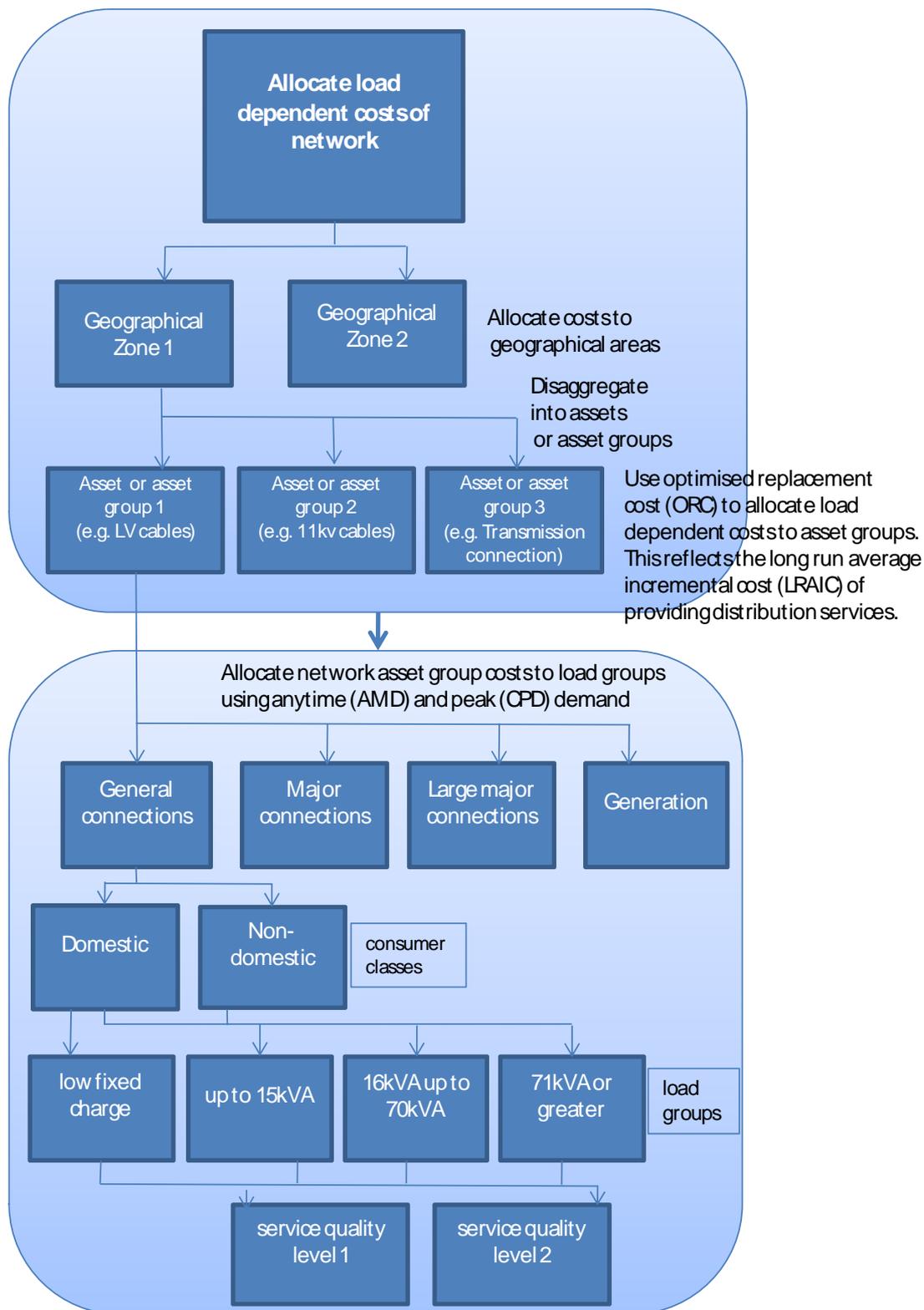


Table 2: Allocation of load-dependent costs to asset groups by supply voltage

Asset Group	User Connection Categories		
	General connections	Major connections	Large major connections
LV cables, lines & plant	x		
Shared distribution substations	x		
11kv cables, lines & plant	x	x	
Zone substations	x	x	
Subtransmission sub-network	x	x	x
Dedicated equipment	x	x	x
Transmission connection	x	x	x

9.5.4 Distributors should use ORC to allocate load-dependent costs to asset groups, as this reflects the LRAIC of providing distribution services. This also has the effect of reducing the variability in costs due to age, and smoothes the recovery of maintenance costs.

Allocating network asset group costs to load groups

9.5.5 Once costs have been allocated by network asset group, they can then be allocated to load groups. The PAWG report recommended the classification of load groups into the following connection categories:

- (a) general connections;
- (b) major connections; and
- (c) large major connections.

9.5.6 The Commission agrees with these classifications, with the addition of distributed generation to accommodate the DG Regulations.

9.5.7 Consistent with the PAWG model approach, distributors should then disaggregate further the general connections assets into the following load groups:

- (a) up to 15kVA;
- (b) 16kVA up to 70kVA; and
- (c) 71kVA or greater.

9.5.8 The general connections load groups should be allocated a consumer classification, either domestic or non-domestic, so as to accommodate the Low Fixed Charge Regulations.

- 9.5.9 It will be necessary to develop a consistent definition for these consumer classes. It is proposed that the definition of a domestic consumer should align with the definition contained in the Low Fixed Charge Regulations, which is as follows:
- (a) “**domestic consumer** means any person who purchases or uses electricity in respect of his or her home”, where
 - (b) “**home** means the domestic premises (as defined in the Electricity Act) that are the principal place of residence of a domestic consumer”, and where
 - (c) “**domestic premises** means any premises that are used or intended for occupation by any person principally as a place of residence”.
- 9.5.10 It is noted that this definition of domestic consumer does not preclude domestic consumers falling within more than one of the three load groups listed above (e.g., up to 15kVA; and 16kVA up to 70kVA).
- 9.5.11 To enable distributors to offer different service levels to network users, within the load group categories listed above distributors should, as appropriate, define load groups further based on service quality (e.g., urban and rural load groups distinguished by different consumer service level commitments).
- 9.5.12 The key cost drivers that should be used for allocating network asset group costs to load groups are the load groups’ demands on the network. These costs can be allocated by using various measures of that demand such as:
- (a) coincident peak demand (**CPD**):
 - (i) using this method, load-dependent costs are allocated among load groups in proportion to their maximum demands at the time of the system peak;
 - (ii) the disadvantage of this approach is that a load group's maximum demand at the time of system peak may be zero, in which case it would receive no allocation of costs. Also, the future load conditions could see a shift in the timing of the peak or the timing of the load group's maximum demand, which would lead to a lack of stability and predictability of future cost allocations;
 - (b) after diversity anytime maximum demand (**AMD**):
 - (i) using this method, load-dependent costs are allocated among load groups in proportion to a load group’s after diversity maximum demand, irrespective of the timing of the system peak. This avoids the disadvantage of the CPD approach, but does not recognise the benefits of the diversity that different load groups provide to a distribution network’s loading;
 - (ii) diversity among load groups varies inversely with load factor, but is not proportional to load factor. This means that load groups with very

high load factors would be more likely to have their maximum demand coincident with the system peak demand and that low load factor groups would provide more diversity – enabling assets to be shared;

- (iii) under this approach the total costs would be spread more evenly over the load groups as a result of the diversity among them. However, the ability to allocate responsibility for system peak demand is diluted.

- 9.5.13 The PAWG recommended using a 50:50 split of AMD and CPD to allocate the network asset group costs to load groups, with the average of each measure being calculated over 100 hours.²⁹ Where distributors diverged from this percentage split or from this number of hours, the PAWG recommended that those distributors should disclose the reasons for any divergence.
- 9.5.14 The Commission supports using a combination of AMD and CPD to allocate costs, as this provides a fair allocation and reduces volatility. Using an average of a certain number of periods to determine the CPD and AMD smoothes the effect of single non-recurring events such as extreme weather or failure of load control systems.
- 9.5.15 The Commission also supports the PAWG recommendation that the number of periods used to calculate the value of the AMD and the CPD should be determined by the distributor for each parameter, with 100 hours used as a guide and reasons given for any divergence.

Allocating transmission costs

- 9.5.16 Distributors will be charged for transmission by Transpower using its approved transmission pricing methodology. The level of the charges will depend upon the location of the distribution network's points of connection on the grid and the distribution network's use of connection and interconnection assets.
- 9.5.17 The calculation of the connection charge involves:
- (a) the use of a valuation allocation methodology for connection assets;
 - (b) maintenance costs relating to connection assets;
 - (c) connection assets' operating costs; and
 - (d) the connection charge calculation.
- 9.5.18 Under its transmission pricing methodology, Transpower's interconnection charges are determined following consideration of four pricing elements:

²⁹ i.e. 200 half-hour demand periods.

- (a) the regional definition, where regions are divided into upper North Island, lower North Island, upper South Island, and lower South Island;
- (b) the number of peak demand periods used;
- (c) the coincident peak allocation; and
- (d) the capacity measurement period.

9.5.19 As discussed earlier in this consultation paper, transmission costs are a subset of load-dependent costs. However, for transparency purposes, the Commission proposes that transmission costs should be identified and allocated separately to distribution costs.

9.5.20 The two most obvious approaches to allocating transmission costs are:

- (a) to pass the transmission price signals directly through to the lowest practicable load group and mirror the basis on which transmission costs are allocated by Transpower to users of the national grid; or
- (b) to treat transmission costs as being additional load-dependent costs and to allocate these in the same manner as other load-dependent costs.

9.5.21 Under the first approach, mirroring the basis on which transmission costs are allocated by Transpower to users of the national grid would mean that:

- (a) transmission connection charges should be allocated to the highest voltage asset group (thereby increasing the quantum of costs in this asset group to be allocated to all users of these assets); and
- (b) transmission interconnection charges should be allocated to each load group in accordance with its contribution to the *regional* coincident peak load.

9.5.22 The primary drawback of this approach is that load groups with demands that are non-coincident with the regional peak demand would avoid all or part of the interconnection charge, which is the majority of the transmission costs.

9.5.23 In contrast, under the second option for allocating transmission costs noted above, both connection charges and interconnection charges would be allocated on the basis of the distribution network's AMD and CPD, thereby spreading the costs across all load groups. However, the drawback of this approach is that the transmission pricing signal is muted.

9.5.24 On balance, the preferred approach is to maintain the pricing signal and mirror the basis on which the transmission costs are allocated by Transpower.

Allocating controllable load costs and benefits

- 9.5.25 Controllable load benefits can be identified in a similar manner to that used to identify the cost of additional load. Where additional load imposes LRAIC on the network, controllable load avoids LRAIC. The impact of the expected savings from load controlled by the distributor through its ripple control system should be allocated to those consumers contributing the controllable load. These savings should take into account the costs of the ripple control (or similar) load management system, on which the distributor should receive a rate of return.

9.6 Allocate load-independent costs

- 9.6.1 As noted earlier in this consultation paper, load-independent costs are the remainder of the total revenue requirement after consumer-specific costs and load-dependent costs have been determined. These costs represent the distributor's overhead (i.e. non-network assets) and could be recovered from users of the distribution network in proportion to each user's demand on the distributor's non-network assets.
- 9.6.2 Hence, a possible allocation of load-independent costs consists of spreading them equally across all ICPs on the distribution network. This would be appropriate for levies that are applied on an ICP basis, such as the Commission's levy for the use of the registry. However, for other overhead costs, it may be appropriate to use a proxy which reflects the use of overhead in servicing different sizes of consumers. An allocation to each load group in proportion to its AMD will reflect the possibility that a large major consumer in a network will consume more overheads than will a small domestic consumer. Other allocations may be more appropriate in individual networks.
- 9.6.3 Therefore, it is proposed that load-independent costs relating to regulatory and/or industry levies that are ICP-based should be allocated as a fixed charge on an ICP basis. The remaining load-independent costs should be allocated as fixed charges across the load groups based on the AMD of the groups or some other well accepted causation-based measure that the distributor can identify and use.

9.7 Deferring network augmentation

- 9.7.1 Recent developments to maintain transmission system security have seen the use of grid support contracts between Transpower and counterparties that are able to reduce transmission peaks by providing controllable load or distributed generation. Load aggregators and distributed generators participated in a pilot scheme in the upper South Island, with positive results for the deferral of grid investment.

- 9.7.2 In a similar vein, the Commission believes that the ability to defer distribution network augmentation via load management and distributed generation should be explored by distributors. Where a specific distribution network investment has the potential to be deferred via the distributor contracting with a load aggregator, distributed generator or other third party, the distributor should enter into a “network support” contract based on the avoided cost of the investment. Under such circumstances, a proportion of the net savings incurred by the distributor in implementing the deferral should be allocated to the counterparty to the network support contract.
- 9.7.3 Where possible, a distributor should identify opportunities for deferring specific network asset investments, and the associated cost savings from doing so, in its asset management plan. The distributor should then contract with parties that are able to assist the distributor to avoid the network investment via the use of load control or distributed generation.
- 9.7.4 The value of controllable load was discussed by the Commission’s load management value and pricing working panel (**VPWP**). The findings of the VPWP are published on the Commission’s website.³⁰ These findings indicate that the value of controllable load for deferral of distribution network investment can be significant.
- 9.7.5 It should be noted that the treatment of distributed generation in this instance differs to its treatment under the DG Regulations, in that the distributed generation is generating to supply the distributor rather than to supply consumer load.

Q3. Do you agree with the proposed approach to the allocation of costs (as set out in figure 4 and table 2)? Please provide specific comments on:

-load dependent costs

-load dependent costs

-load independent costs, including:

-Geographic zones

-Asset groups

-load group classifications

-AMD and CPD to allocate the network asset group costs to load

Groups

³⁰ <http://www.electricitycommission.govt.nz/pdfs/opdev/retail/consultationdocs/loadmgt/Appendix-One.pdf>

-transmission costs

Q4. Do you agree with the proposed approach to allocating the net benefits of deferred network augmentation?

10. Price signalling

10.1 Introduction

10.1.1 Following the categorisation and allocation of costs, the third key stage of the proposed model approach is to set out the intent of the distribution price signals to be issued.

10.2 PAWG model approach to price signalling

10.2.1 The PAWG described the general form of an efficient price as including:

- (a) a fixed price component, which recovers consumer-specific costs and may include further fixed price components based on the installed, or contract, capacity. The fixed price component of a distribution price is designed so that it does not incentivise a consumer to use / not use the network at a specific time; and
- (b) a variable price component aimed at signalling critical peak periods in the network, which reflects the cost of expanding the network to relieve the congestion. Therefore, it will be a price that applies to marginal demand and incentivises a consumer not to use the network at a specific time.

10.2.2 The PAWG proposed that network congestion should be signalled through dynamic congestion period signalling, using posted (rather than dynamic) prices. These price signals would only arise at times when the network was congested or nearing congestion (i.e., demand was reaching security, or other, limits which required the distributor to exercise load control). The PAWG recommended that the posted price should be set to signal the cost of upgrading the network to relieve congestion, and that the congestion (critical peak) periods should be limited to approximately 100 hours.

10.2.3 Where dynamic signalling of critical peak periods was not possible, the PAWG recommended that posted peak periods could be used, with different prices for peak and shoulder demand periods. Shoulder demand periods are periods immediately before and after the congestion (critical peak) period. Shoulder demand pricing is used to discourage consumers merely shifting the peak, rather than reducing it.

10.3 Discussion

10.3.1 Although theoretically not as efficient as dynamic pricing and dynamic congestion periods, the PAWG recommended approach to signalling distribution prices

acknowledged the implementation complexity and costs associated with dynamic pricing and the uncertainty that consumers would face under it.

- 10.3.2 The Commission considers that the PAWG model approach to signalling network congestion represents an acceptable trade-off between economic efficiency and price certainty for consumers and distributors. As the PAWG noted, LRAIC is a long-term forward-looking cost, and therefore efficiency losses arising from using posted rather than dynamic prices should be relatively small.
- 10.3.3 Encouraging efficient use of distribution network assets in peak periods through TOU pricing, which is intended to reflect the cost of investing in the network to avoid congestion, will further the Commission's efficiency principle. Designing the pricing to ensure that prices are low in off-peak periods will provide consumers with an opportunity to manage their costs, will lower losses, and will reduce overall costs for the distributor, thereby leading to least cost provision of distribution services. Opportunities also exist for demand side management by consumers, or investment in demand side management by the distributor or a third party. This furthers the Commission's objective to remove barriers to demand side participation and new technologies.
- 10.3.4 Based on the systems available, the PAWG concluded that only critical peak period price signalling (**CPP pricing**) using ripple control would be practicable in most cases. However, the anticipated rollout of large numbers of advance meters with two-way communication³¹ extends the capability of distributors to signal critical peak periods and possibly signal dynamic prices.
- 10.3.5 In conclusion, the Commission has adopted the PAWG model approach to signalling network congestion using CPP pricing. Pricing should only influence consumption behaviour during network congestion periods, and to achieve this, price signals ideally should be communicated by distributors to consumers using multi-part tariffs with fixed and variable (\$/kVA/yr) components. In addition to varying with time of use, price signals should:
- (a) be locational;
 - (b) reflect LRAIC; and
 - (c) enable the distributor to achieve its revenue requirement.

³¹ Report on international experience with smart meters (energy), Prepared for: The Parliamentary Commissioner for the Environment, Strata Energy Consulting Limited, May 2008.

10.4 Price signalling proposal

10.4.1 Consistent with the discussion above, the Commission proposes the following approach to signalling distribution prices:

- (a) distributors should signal network congestion via posted demand prices and, where it is cost-effective to do so, dynamic critical peak periods;
- (b) distributors should offer controllable load contracts with dynamic signalling of critical peak periods and with prices based on the deferral value of the network investment; and
- (c) distributors should offer retail delivery pricing as a standard offer, to provide price signals at all connection points on the distribution network.

10.5 Price structure proposal

10.5.1 Consistent with the PAWG model approach, the Commission proposes the following approach to the structure of distribution prices:

- (a) where it is not cost-effective to dynamically signal critical peaks to consumers (and/or impractical for consumers to respond to dynamic price signals), it is proposed that distributors should:
 - (i) pre-define high price periods to approximate critical peak periods;
 - (ii) for winter-peaking networks, consider using the standard high price periods of 7am to 11am, and 5pm to 9pm, on winter weekdays;
 - (iii) for summer-peaking networks, publish the high price periods used to approximate critical peak periods;
 - (iv) restrict the high price period to the season in which the critical peak periods usually occur; and
 - (v) in addition to the above high price periods, define shoulder periods either side of each high price period, if appropriate.

Q5. Do you agree with the proposed approach to signalling critical peak periods and shoulder periods via distribution prices?

Q6. Do you agree with the approach to structuring distribution prices?

11. Model price structure

11.1 Introduction

11.1.1 The fourth and final key stage of the proposed model approach is to set out the model price structures to be used as a guideline by distributors.

11.2 PAWG model approach to determining a price structure

11.2.1 Based on its analysis of costs and pricing, the PAWG provided a derivation of model price structures for connections with and without half-hourly metering. The PAWG recommended that the general form of prices should consist of fixed and variable components. However, it was noted that price components may differ depending on the information available (i.e. geographic zones, ICP connection or contract capacity, and load groups that reflect different load characteristics).

11.2.2 The PAWG noted that the division of a connection category into load groups to reflect different load characteristics would only be carried out where half-hourly metered data was unavailable. Where half-hourly metering was available, the connection category would be the same as the load group, including for general connections.

11.2.3 The PAWG proposed that the model price structure for half-hourly metering should include:

- (a) a fixed price component that recovers consumer-specific and load-independent costs;
- (b) a fixed capacity price component based on contracted or agreed capacity (in kVA) or the preceding year's peak demands (in kVA); and
- (c) a variable critical peak period price component that reflects LRAIC, which is charged on demand in excess of the capacity to which the fixed capacity price component relates.

11.2.4 For consistency purposes, the PAWG proposed that the same price structure should be used for half-hourly metered connections and non-half-hourly metered connections (most general connections). Moreover, it was proposed that the price structure for general connections should provide for half-hourly and multi-rate metering options, while recognising that currently most meters measure only energy consumption.

11.2.5 It was noted that, for general connections without half-hourly metering, the ICP metered data that is generally available is:

- (a) for anytime delivery, energy consumption or average demand (calculated as the energy consumption divided by the time over which it is measured);
- (b) for critical peak period delivery, energy consumption or average demand;
- (c) for time-of-use delivery (e.g. day/night) – energy consumption or average demand; and
- (d) for controllable delivery, energy consumption when not controlled.

11.2.6 It was also noted that the price signals that can be sent to consumers to encourage demand reduction during critical peak periods include:

- (a) higher prices for consumption in critical peak periods relative to other times. To signal the potentially higher costs imposed by uncontrollable consumption during critical peak periods, there should be two distinct prices:
 - (i) one for delivery during the critical peak period(s), which may be signalled dynamically, or posted; and
 - (ii) another for delivery at all other times;
- (b) lower prices for consumption during off-peak periods, or compensating consumers for controllable load.

11.2.7 On the basis of the above points, the PAWG recommended that general connections without half-hourly or multi-rate metering should have a price structure that includes:

- (a) a fixed price component that recovers the consumer-specific costs, load-independent costs and, if appropriate, the capacity part of the load-dependent costs; and
- (b) a variable average demand or consumption component using high, shoulder and low prices.

11.2.8 The PAWG noted that, while some of the costs for general connections are fixed and should be reflected in fixed (capacity) prices, the Government has passed regulations requiring a low fixed price option for domestic consumers, thereby meaning that the fixed prices for some consumers may not align with the fixed costs of supplying those consumers.

11.3 PAWG's model price structure

11.3.1 In summary, the PAWG recommended the following model price structures for half-hourly metered and non-half-hourly metered consumers.

Half-hourly metered consumers

- 11.3.2 That distributors should recover target revenue from large major, major and general connections with half-hourly metering through:
- (a) a fixed price component that recovers consumer-specific costs and load-independent costs;
 - (b) a fixed capacity price component based on contracted or agreed capacity (in kVA) or the preceding year's peak demands (in kVA) at the connection point; and
 - (c) a variable critical peak period price component that reflects LRAIC, which is charged on demand in excess of the capacity to which the fixed capacity price component relates.

Non-half-hourly metered consumers

- 11.3.3 That distributors should recover target revenue from general connections without half-hourly or multi-rate metering through:
- (a) a fixed price component that recovers consumer-specific costs, load-independent costs and, if appropriate, the capacity part of the load-dependent costs; and
 - (b) a variable average demand or consumption component using high, shoulder and low prices.
- 11.3.4 The PAWG recognised that it would be necessary to covert these prices to aggregate options by the application of typical load profiles, because of the base of existing metering and present technical and economic limitations.

11.4 Discussion

- 11.4.1 The model pricing structures proposed by the PAWG are consistent with the analysis of cost allocation and efficient pricing undertaken in the PAWG report and in this consultation paper.
- 11.4.2 However, the PAWG model approach accommodates the use of both the RDM and the WDM. As noted earlier in this consultation paper, the Commission is proposing the proposed model approach whereby distributors should only use the RDM when offering distribution prices. The Commission's initial view is that the RDM has a number of benefits over the WDM including:
- (a) providing a greater incentive on distributors to minimise losses by sharing the risks of network losses and constraints across distributors and consumers, rather than placing all of the risks on consumers;

- (b) increasing cost-reflectivity and reducing cross-subsidisation between general connections;
- (c) providing greater transparency of distribution prices;
- (d) providing appropriate signals at the point of connection (as opposed to the GXP) to manage transmission and distribution losses and constraints (e.g., via load control);
- (e) costs can be disaggregated to reflect service level differences across a distribution network; and
- (f) enabling general connection consumers to understand how their individual distribution charge is determined.

- 11.4.3 The PAWG model approach refers to peak, off-peak and shoulder periods for consumers without half-hourly or multi-rate meters. However, no guidance is given on what the ratios might be for peak to off-peak prices and peak to shoulder prices, in order to send pricing signals that are sufficiently strong as to curtail load. The Commission is interested in receiving feedback on this matter and whether it might be necessary to undertake some pilot studies on consumer responses to different distribution price ratios.
- 11.4.4 In future refinements to the proposed model approach the Commission may wish to initiate some studies on the efficient use of CPP and TOU structures. The PAWG report suggests that the CPD and AMD periods be set at 100 hours in a year. However, the number of periods used to determine the average CPD and average AMD may require analysis of load profiles and demand response.
- 11.4.5 The PAWG report refers to recovering capacity costs in \$/kVA only. It makes no reference to distributors recovering capacity costs by using demand charges measured in \$/kW. The difference between the quantities being charged to a specific consumer under these two approaches would be determined by the power factor at the point of connection – the higher the power factor, the more equivalent will be the kVA and kW prices; the lower the power factor, the higher the kW price vis-à-vis the kVA price.
- 11.4.6 An alternative to kVA charging is to charge for kW and kVA_{rh} separately. A distributor could set a target power factor for points of connection and charge when this power factor was not met in a demand period. The charge for not meeting the power factor in a demand period, and thereby not minimising reactive power on the network, would be \$/kVA_{rh}. So, for example, if a distributor wanted to achieve an average power factor of 0.95 across the network, that distributor could impose a charge for excess kVA_{rh} on points of connection where the ratio of kVA_{rh} to kWh was greater than 33% for a demand period. The Commission is interested in receiving submissions on the merits of a model pricing approach allowing for \$/kW charges, coupled with \$/kVA_{rh} charges in instances where a target power factor is not met.

11.4.7 As noted earlier in this consultation paper, new technologies such as AMI and ADR are overcoming limitations in current non-half-hourly metering with respect to price signals, by enabling two-way communication to the ICP level for general connections, and thereby enabling more dynamic distribution and retail pricing. The potential for home area networks with price-responsive appliances is also growing. Consistent with the requirements of the GPS, the Commission believes that, at a minimum, distributors should be encouraging the use of demand-side management through the use of load control, either via existing load control technologies or via newer technologies such as AMI and ADR. To this end the Commission proposes that all load groups should have some form of controlled load pricing option, to encourage demand response – either passively via the distributor using load control, or actively (e.g., via ADR).

11.4.8 The Commission considers that a key element of the proposed model approach is consistency of terminology. Given the significant number of distributors in New Zealand, difficulties can arise from differences in terminology across distributors. Additionally, terminology can and does evolve over time to reflect industry developments. By way of example, in recent years, the terms CPP pricing and TOU pricing have become prevalent in discussions around demand response and improving network efficiency.³² The proposed model approach incorporates the use of these two terms. The Commission recommends that distributors adopt not only these two particular terms in their price structures, but that distributors adopt all of the key terminology used in the proposed model approach.

11.5 Proposed further development of price structures

11.5.1 The Commission proposes to adopt the PAWG model approach to model price structures, with the following additional developments:

- (a) distributors should offer RDM pricing as a standard, to enable distribution price signals to be available at all connection points on a distribution network;
- (b) all load groups should have a form of controlled load pricing option to encourage automated demand response;
- (c) there should be consistency of key distribution pricing terminology across all distributors.

Q7. Do you agree with the model structure? Are there reasonably practicable alternatives?

³² International and domestic electricity tariffs and tariff structures, LECG, May 2008.

12. Meeting the Guiding principles

12.1 Consideration against guiding principles

Table 2: Consideration of proposed model approach against guiding principles

Guiding principle	Proposed model approach
A distribution pricing methodology should:	
encourage the efficient and fair allocation of costs, avoiding cross-subsidisation and unfair discrimination	Costs can be differentiated by consumer class, geographic zones and by service level, thereby reducing cross-subsidisation between general connections
be stable and predictable in respect of revenue for the distributor and charges to consumers	Is predictable in respect of consumer charges. However, changes in consumer consumption can cause unpredictable revenue for distributors who may over- or under-recover their revenue requirement from consumers
be practicable to implement without placing significant transaction costs on consumers and distributors	Overall, reasonably practicable to implement for distributors, as information is generally available for cost allocation purposes, and where half-hourly or multi-rate metering is not yet available for general connection cost allocation and pricing purposes, profiling can be used. Assuming price signal changes are managed, then there should be little if any adverse effect on consumers
Changes to a distribution pricing methodology (and the rationale for them) should be widely publicised and follow consultation with interested parties. The revised distribution pricing methodology should be transparent, with the results predictable and readily verifiable	The proposed model approach will be subject to widespread consultation with interested parties. The PAWG methodology has been implemented by some distributors and the Commission will monitor the outcomes of the proposal. Distributors will have the flexibility to adjust the pricing methodology to suit their particular circumstances

Guiding principle	Proposed model approach
Distribution prices should:	
encourage the efficient use of electricity distribution services	Cost-reflective prices disaggregated to the ICP level signal to all consumers the network-related costs associated with taking load, thereby facilitating efficient use of the network by consumers. However, the influence on electricity usage will depend on the extent to which price signals are passed on to end users
encourage efficient investment in distribution, transmission, distributed generation (including renewable generation), and technology innovation	Providing LRAIC pricing signals should facilitate efficient investment in distribution assets and non-distribution assets over time, by signalling to consumers the incremental costs associated with additional consumption during peak periods on capacity constrained distribution networks
not create barriers for retail competition and the provision of distribution or other services	A common approach to distribution pricing should reduce barriers to the expansion of retail competition across networks by reducing the complexity of pricing and billing for retailers
provide appropriate signals to manage transmission and distribution losses and constraints	The proposed model approach provides appropriate signals to <i>retailers</i> and <i>end users</i> at end users' points of connection to manage transmission and distribution losses and constraints, via the use of LRAIC, TOU pricing and the pass through of transmission price signals
relate to the quality and reliability of service delivered, including the risks of delivery	<p>Costs can be disaggregated to reflect service level differences across a distribution network</p> <p>Risks of delivery, in the form of network losses and constraints, are shared by the distributor and consumers thereby providing at least a short-term incentive for the distributor to minimise losses</p>
be easily understood	The proposed approach is not dissimilar to existing methodologies and should be understandable by an informed lay person

12.2 Conclusion

- 12.2.1 The proposed model approach meets most of the guiding principles satisfactorily. However, the ability to gain the benefits of economically efficient pricing signals is achievable only in cases where the distributor supplies distribution services directly to end users. This occurs when the distributor has a conveyance agreement with the retailer supplying electricity to the end user.
- 12.2.2 Where the distributor supplies those services through an interposed arrangement with a retailer, the retailer is at liberty to pass the signals on to the end user, augment them, or mute them.

Q8. Do you agree that the proposed model approach meets the guiding principles appropriately?

13. Implementation issues and next steps

13.1 Transition to implementation

- 13.1.1 From the information that the Commission has obtained from distributors, it is clear that some distributors have adopted the PAWG model approach – using either the RDM or the WDM.
- 13.1.2 At this time, the Commission has insufficient information to ascertain the extent to which the PAWG report's RDM recommendations have been implemented by the distributors that use the RDM.
- 13.1.3 As noted earlier in this consultation paper, the WDM is used by seven distributors (although it is also noted that two distributors are currently considering whether to move from the WDM to the RDM).
- 13.1.4 While noting that the proposed model approach will be voluntary, the Commission is seeking information on what would be involved for distributors and retailers to change from an existing pricing methodology and what, if any, impacts there would be on consumers.

13.2 Monitoring the uptake

- 13.2.1 The Commission is interested in obtaining views on an effective, practicable and low cost means by which to monitor the uptake of the proposed model approach by distributors. The Commission's preliminary view is that monitoring should be by annual self-reporting on a material exceptions basis (in a Statement of Variations from the Voluntary Model Approach).
- 13.2.2 The Commission's preliminary view is that, rather than being overly prescriptive, the self-reporting should be principle-based, including:

- (a) the level of reporting on the pricing methodology should be in line with the requirements of the Electricity Distribution (Information Disclosure) Requirements or subsequent developments. Under paragraph 14 of those requirements, the requirements in paragraphs 22 and 23 of the 2004 Electricity Information Disclosure Requirements continue to apply :

22. Disclosure of pricing methodologies—

Every disclosing entity must publicly disclose,-

- (a) *At the beginning of each financial year, the methodology used at the beginning of that financial year to determine the line charges payable or to be payable; and*

- (b) *Any change in the methodology or adoption of a different methodology, within 1 month of the change or the different methodology taking effect.*

23. Contents of pricing methodology disclosures—

Every disclosure under requirement 22 must—

- (a) *Describe the methodology used to calculate the prices charged or to be charged; and*
 - (b) *Include the key components of the revenue required to cover costs and profits of the disclosing entity's line business activities, including cost of capital and transmission charges, which must include the numerical value of each of the components; and*
 - (c) *State the consumer groups used to calculate the prices charged or to be charged, including—*
 - (i) *The rationale for the consumer grouping; and*
 - (ii) *The method by which the disclosing entity determines which group consumers are in; and*
 - (iii) *For each of these consumer groups, the statistics relating to that group which were used in the methodology; and*
 - (d) *Describe the method by which the disclosing entity allocated the components of the revenue required to cover the costs of its line business activities amongst consumer groups, which must include the numerical values of the different components allocated to each consumer group and the rationale for allocating it in this manner; and*
 - (e) *Describe the method by which the disclosing entity determined the proportion of its charges which are fixed and the proportion which are variable, and the rationale for determining the proportions in this manner.*
- (b) distributors should provide sufficient detail to be clear as to why their methodology varies from the proposed model approach including, if necessary, a high level cost/benefit analysis demonstrating why changing their current methodology would be to the detriment of their customers;
 - (c) the date for the first Statement of Variations from the Voluntary Model Approach to be provided to the Commission should be one year after the voluntary model approach has been published.

Q9. Do you agree this is an effective and practicable approach to monitoring uptake? Are there alternatives that are more effective and practicable to implement?

13.3 Next steps

13.3.1 Before finalising its model approach, the Commission will:

- (a) organise a workshop to discuss the proposed model approach, prior to the closing date for submissions;
- (b) review submissions and develop a draft decision paper;
- (c) publish a draft decision paper for submissions; and
- (d) review submissions and publish a final decision.

13.3.2 This process of consultation means that the Commission envisages that a final decision will be made towards the end of 2009.

Appendices

Appendix 1	Commission's principal objectives and specific outcomes as set out in the Electricity Act	69
Appendix 2	Requirements for the distribution methodologies as set out in the 2009 GPS	70
Appendix 3	Regulated distributor tariff option provisions in Low Fixed Charge Regulations	71
Appendix 4	Pricing principles in DG Regulations	74
Appendix 5	Submission questions	77
Appendix 6	Format for submissions	78

Appendix 1 Commission's principal objectives and specific outcomes as set out in the Electricity Act

In developing a model approach to a distribution pricing methodology the Commission must meet its principal objectives and the specific outcomes set out in the Electricity Act 1992 as follows:

172N Principal objectives and specific outcomes

- (1) *The principal objectives of the Commission in relation to electricity are -*
 - (a) *to ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable and environmentally sustainable manner; and*
 - (b) *to promote and facilitate the efficient use of electricity.*
- (2) *Consistent with those principal objectives, the Commission must seek to achieve, in relation to electricity, the following specific outcomes:*
 - (a) *energy and other resources are used efficiently.*
 - (b) *risks (including price risks) relating to security of supply are properly and efficiently managed.*
 - (c) *barriers to competition in electricity are minimised for the long-term benefit of end-users.*
 - (d) *incentives for investment in generation, transmission, lines, energy efficiency, and demand-side management are maintained or enhanced and do not discriminate between public and private investment.*
 - (e) *the full costs of producing and transporting each additional unit of electricity are signalled.*
 - (f) *delivered electricity costs and prices are subject to sustained downward pressure.*
 - (g) *the electricity sector contributes to achieving the Government's climate change objectives by minimising hydro spill, efficiently managing transmission and distribution losses and constraints, promoting demand-side management and energy efficiency, and removing barriers to investment in new generation technologies, renewables and distributed generation.*

Appendix 2 Requirements for the distribution methodologies as set out in the 2009 GPS

The Government's requirements for distribution pricing methodologies are set out in the GPS as follows:

“100. The Commission should develop, in consultation with interested parties, principles or model approaches to distribution pricing and monitor their uptake. The Commission should recommend regulations if required to ensure compliance. As part of this work the Commission should investigate barriers to demand side participation.

101. The diversity and complexity of the terms and conditions offered by different lines companies for use of their lines is often cited as a significant barrier to expansion of retail competition. The Commission should consider whether standardisation and simplification of tariff schedules and contractual arrangements would facilitate market entry by retailers.

102. The Government expects distribution companies to keep any changes to rural line charges in line with changes to urban line charges. The Commission should monitor developments in rural charges.”

Appendix 3 Regulated distributor tariff option provisions in Low Fixed Charge Regulations

13. Purpose

- (1) The purpose of regulations 14 to 17 is to regulate the way in which electricity distributors charge in respect of homes on low fixed charge tariff options, so as to assist electricity retailers to deliver low fixed charge tariff options.

14. Regulated distributor tariff option

- (1) An electricity distributor must ensure that any arrangement it has with an electricity retailer in respect of a home that is on a bundled low fixed charge tariff option, and that any arrangement it has with a domestic consumer in respect of a home that is on a split-charging low fixed charge tariff option, complies with the following minimum requirements:
 - (a) the electricity distributor must not charge more than 1 fixed charge for the line function services supplied to the home; and
 - (b) that fixed charge must be not more than 15 cents per day, excluding goods and services tax; and
 - (c) the electricity distributor may not recover any charges associated with the delivered electricity supplied to the home other than by all or any of the following:
 - (i) the fixed charge referred to in paragraph (b); and
 - (ii) a variable charge or charges; and
 - (iii) any fees for special services; and
 - (iv) any fee payable for providing or reading any meter that is owned by the electricity distributor; and
 - (v) any fee payable for providing any relay that is owned by the electricity distributor.
- (2) If a home is not on a low fixed charge tariff option, the electricity distributor's arrangement with the electricity retailer in respect of that home must treat that home as not being on a regulated distributor tariff option (unless the electricity distributor has only regulated distributor tariff options).

15. Regulation of variable charges in regulated distributor tariff option

- (1) The variable charge or charges in a regulated distributor tariff option must be such that the average consumer would pay no more in total per year for the fixed charge and variable charges charged in accordance with regulation 14(c)(i) and (ii) than the average consumer would pay in total per year for those same matters on any alternative distributor tariff option.

- (2) In determining whether the tariff options comply with subclause (1), the following rules must be applied:
 - (a) subclause (1) must be complied with both before and after any discounts or rebates or other distributions are applied or made:
 - (b) if there is more than 1 variable charge on a tariff option, the average consumer is assumed to consume electricity on the following ratios (unless the average consumer in that supply area in fact consumes on a different ratio or is on a different delivered electricity package):
 - (i) for separately charged controlled and uncontrolled anytime electricity consumption, 40% of total consumption is controlled and 60% is uncontrolled:
 - (ii) for separately charged controlled night and uncontrolled anytime electricity consumption, 25% of total consumption is controlled and 75% is uncontrolled.

16. Regulation of other charges and other terms and conditions of regulated distributor tariff option

- (1) A regulated distributor tariff option must not contain—
 - (a) variable charges for domestic consumers that are tiered or stepped according to the amount of electricity consumed; or
 - (b) fees for special services, rebates, or discounts that are inconsistent with the fees for special services, rebates, or discounts that apply to domestic consumers who are on alternative distributor tariff options; or
 - (c) other terms and conditions that are inconsistent with the terms and conditions of alternative distributor tariff options.
- (2) Subclause (1)(a) does not prevent an electricity distributor from doing any of the following things:
 - (a) setting different variable charges for controlled and uncontrolled load, or for electricity consumption at different times of the day or year, provided that the different variable charges are not tiered or stepped according to the amount of electricity consumed:
 - (b) setting rebates or discounts that vary according to the amount of electricity consumed, provided that the rebates or discounts applying to domestic consumers on low fixed charge tariff options are consistent with those that apply to domestic consumers who are on alternative distributor tariff options.

17. Distributors providing wholesale pricing

- (1) If an electricity distributor charges an electricity retailer on the basis of the quantity of electricity metered in bulk at a grid exit point (wholesale pricing), the distributor is treated as complying with regulations 14 to 16 if there is a wholesale tariff option available to the electricity retailer, referable to homes, that includes a fixed charge at not more than 15 cents per day per home (exclusive of goods and service tax) and

the distributor's wholesale tariff option is in all other respects consistent with the purpose referred to in regulation 13.

Appendix 4 Pricing principles in DG Regulations

Schedule 4 Pricing Principles

1. This schedule sets out the pricing principles to be applied for the purposes of these regulations in accordance with regulation 12 (which relates to clause 20 of Schedule 2 and clause 4 of Schedule 3).

2. The pricing principles are—

Charges to be based on recovery of reasonable costs incurred by distributor to connect the generator and to comply with connection and operation standards within the network, and must include consideration of any identifiable avoided or avoidable costs

- (a) subject to paragraph (i) connection charges in respect of distributed generation must not exceed the incremental costs of providing connection services to the distributed generation. For the avoidance of doubt, incremental cost is net of transmission and distribution costs that an efficient service provider would be able to avoid as a result of the connection of the distributed generation:
- (b) costs that cannot be calculated (eg, avoidable costs) must be estimated with reference to reasonable estimates of how the distributor's capital investment decisions and operating costs would differ, in the future, with and without the generation:
- (c) estimated costs may be adjusted ex post. Ex-post adjustment involves calculating, at the end of a period, what the actual costs incurred by the distributor as a result of the distributed generation being connected to the distribution network were, and deducting the costs that would have been incurred had the generation not been connected. In this case, if the costs differ from the costs charged to the generator, the distributor must notify and recover or refund those costs after they are incurred (unless the distributor and the generator agree otherwise):

Capital and operating expenses

- (d) where costs include distinct capital expenditure, such as costs for a significant asset replacement or upgrade, the connection charge attributable to the generator's actions or proposals is payable by the generator before the distributor has committed to incurring those costs. When making reasonable endeavours to facilitate connection, the distributor is not obliged to incur those costs until that payment has been received:
- (e) where incremental costs are negative, the generator is deemed to be providing network support services to the distributor, and may invoice the distributor for this service and, in that case, the generator must comply with all relevant obligations (for example, obligations under these regulations and in respect of tax):

- (f) where costs relate to ongoing or periodic operating expenses, such as costs for routine maintenance, the connection charge attributable to the generator's actions or proposals may take the form of a periodic charge expressed in dollars per annum:
- (g) before the connection of distributed generation, the distributor must notify the generator in writing of the connection charges that will be payable, and explain how the connection charges have been calculated:
- (h) after the connection of the distributed generation, the distributor may review the connection charges payable by a generator not more than once in any 12-month period. Following a review, the distributor must notify the generator in writing of any change in the connection charges payable, and the reasons for any change, not less than 3 months before the date the change is to take effect:

Share of generation-driven costs

- (i) if multiple generators are sharing an investment, the portion of costs payable by any one generator—
 - (i) must be calculated so that the charges paid or payable by each generator take into account the relative expected peak of each generator's injected generation; and
 - (ii) may also have regard to the percentage of assets that will be used by each generator, the percentage of capacity used by each generator, the relative share of expected maximum combined peak output, and whether the combined peak generation is coincident with the peak load on the network:
- (j) in order to facilitate the calculation of equitable connection charges under paragraph (i), the distributor must make and retain adequate records of investments for a period of 5 years, provide the rationale for the investment in terms of facilitating distributed generation, and indicate the extent to which the associated costs have been or are to be recovered through generation connection charges:

Repayment of previously funded investment

- (k) if a generator has paid connection charges that include (in part) the cost of an investment that is subsequently shared by other generators, the distributor must refund to the generator all connection charges paid to the distributor under paragraph (i) by other generators in respect of that investment:
- (l) if there are multiple prior generators, a refund to each generator referred to in paragraph (k) must be provided in accordance with the expected peak of that generator's injected generation over a period of time agreed between the generator and the distributor.

The refund—

- (i) must take into account the relative expected peak of each generator's injected generation; and
 - (ii) may also have regard to the percentage of assets that will be used by each generator, the percentage of capacity used by each generator, the relative share of expected maximum combined peak output, and whether the combined peak generation is coincident with the peak load on the network:
- (m) no refund of previous payments from the generator referred to in paragraph (k) is required after a period of 3 years from the initial connection of that generator:

Non-firm connection service

- (n) to avoid doubt, nothing in these regulations creates any capacity or property rights in any part of the distribution network unless these are specifically contracted for. Distributors must maintain connection and lines services to generators in accordance with their connection and operation standards.

2. In this schedule, incremental costs means the reasonable costs that an efficient service provider would incur in providing electricity distribution services with connection services to the distributed generation, less the costs that the efficient service provider would incur if it did not provide those connection services.

Appendix 5 Submission questions

The Commission welcomes submissions on the following:

- Q1. Do you agree with the content of these proposed guiding principles? Are there alternative or additional guiding principles that should be considered?**
- Q2. Do you agree that the RDM should be the preferred approach?**
- Q3. Do you agree with the proposed approach to the allocation of costs (as set out in figure 4 and table 2)? Please provide specific comments on:**
- load dependent costs
 - load independent costs, including:
 - Geographic zones
 - Asset groups
 - load group classifications
 - AMD and CPD to allocate the network asset group costs to load groups
 - transmission costs
- Q4. Do you agree with the proposed approach to allocating the net benefits of deferred network augmentation?**
- Q5. Do you agree with the proposed approach to signalling critical peak periods and shoulder periods via distribution prices?**
- Q6. Do you agree with the approach to structuring distribution prices?**
- Q7. Do you agree with the model structure? Are there reasonably practicable alternatives?**
- Q8. Do you agree that the proposed model approach meets the guiding principles appropriately?**
- Q9. Do you agree this is an effective and practicable approach to monitoring uptake? Are there alternatives that are more effective and practicable to implement?**

Appendix 6 Format for submissions

6.1.1 If possible, submissions should be provided in the format shown in this appendix. Your submission is likely to be made available to the general public on the Commission’s website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Commission on a confidential basis. However, all information provided to the Commission is subject to the Official Information Act 1982.

Question No.	General comments in regards to the:	Response