MODEL APPROACHES
TO DISTRIBUTION PRICING

Second Paper

prepared by the

Pricing Approaches Working Group

2 February 2005

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1. Executive Summary

1.1 Overview

The Pricing Approaches Working Group (PAWG) is a consultative group formed for the purpose of developing voluntary model approaches to distribution pricing. This Paper 2 has been prepared by PAWG as part of the process to "develop model approaches to distribution pricing by defining principles, methodologies and framework."

The principles adopted by PAWG are the Guiding Principles that were developed by the Model Distribution Arrangements Project (MDAP) established under the Metering and Reconciliation Information Agreement (MARIA). PAWG has focussed on certain key objectives of the Guiding Principles, in particular, that distribution prices should:

- provide efficient price signals for utilisation of and investment in the network,
- relate to the level of service and reflect the cost structures and risks and be easily understood; and
- encourage technology innovation.

Regulatory factors have also been taken into account. Under Part 4A of the Commerce Act the Commerce Commission has introduced a regulatory regime consisting of a price path threshold and a quality threshold that, if breached, may lead to an inquiry and possible declaration of control. This paper does not address the setting of total revenues, which will be set by each lines business subject to the regulatory regime. Where references are made to "costs" in this paper, they are references to the target revenue components set by the lines business to recover various cost components and are not references to total costs or cost components as calculated using a "building blocks" approach.

Furthermore, this paper considers only the core distribution services. Additional services that a Distributor may choose to offer, such as enhanced quality above the core service level and additional controllable/interruptible load services for the energy market, are outside the core distribution services.

Both the transmission pricing methodology and the contractual counter-party for the provision of transmission services are currently being reviewed by the Electricity Commission. Therefore it is uncertain whether transmission costs will, in the future, be recovered through distribution prices. Therefore PAWG has not developed methodologies for the pass-through of current transmission costs. If it is subsequently decided that the existing contractual arrangements between Transpower and Distributors will continue into the future, and once the form of future transmission costs becomes certain, the pass-through of transmission costs will be considered then.

Another issue that has been deferred for later consideration is the pricing of services to distributed generators. This has been deferred pending the release of the final version of the Government Policy Statement for Electricity, which is likely to include the Government's policy on distributed generation. This deferment will enable issues relating to distribution pricing to Consumers and Retailers to be resolved first. The way in which distribution services are priced to distributed generators should be consistent with the way in which services are priced to Consumers with controllable load but will need to take into account the effects of bi-directional current flows on network cost drivers.

The approach that has been adopted by PAWG in developing its recommendations for pricing distribution services to Retailers and/or Consumers is to first review current approaches and then to develop a framework for the model approaches. Aspects of some of the current methodologies have been carried over to the model approaches such as the categorisations of costs, disaggregation of the network into asset groups and categorisation of loads. Some changes to the levels of disaggregation are recommended with a view to simplifying the methodologies.

Where there are fundamental, rather than detailed, differences in the current approaches PAWG has endeavoured to resolve the differences or at least identify them and their effects on prices. One such difference is that between an average cost approach compared to an incremental cost approach. PAWG concludes that given the practical issues in pricing distribution services, prices that aim to reflect the incremental cost will generally reflect some form of long run average cost, or a form of long run incremental cost that is defined in such a way as to be equivalent.

Another fundamental difference in current approaches is the use of either a Wholesale or a Retail Delivery Model. With the Wholesale Delivery Model, distribution services are provided to Retailers on the basis of their reconciled aggregated bulk sales volumes measured at the grid exit points (GXPs). In the Retail Delivery Model, under interposed arrangements, distribution services are provided to Retailers on the basis of sales volumes measured at Consumers' installation control points (ICPs). With conveyance arrangements distribution services are provided directly to Consumers but may be, and usually are, billed via Retailers.

Although the costs and revenue risks to the Distributor with the Wholesale Delivery Model are less than with the Retail Delivery Model, the Wholesale Delivery Model dilutes the price signals to Consumers without half-hourly metering and may be less effective in differentiating prices for providing different service quality levels to Consumers.

Prices using the proposed price structures (see section 1.2) and set to recover the target revenues (i.e. the costs allocated to each Load Group using each Network Asset Group) will promote efficient use of and investment in the network by providing price signals of where and when the network is at or close to its maximum loading (Congestion Period).

They will also make the allocation of costs, and in particular Load-Dependent Costs, more transparent and simplify the price structures by setting out a transparent process of cost allocation, limiting the number of different Load Groups to which Load-Dependent Costs are allocated and requiring a greater degree of transparency around the load profiles used to allocate those costs.

They are also aimed at encouraging technological innovation by promoting more dynamic price signalling and providing incentives for enhanced metering where this is or may become cost effective.

By providing a common and more transparent framework for allocating costs and calculating prices, some of the concerns of Retailers and Consumers are addressed. The greater degree of commonality and consistency of pricing will reduce the complexity and costs faced by Retailers who are selling on a national basis in several different networks. They will also address Consumers' concerns about the lack of transparency in prices but only if supported by appropriate information disclosure regulations that require Distributors to disclose prices and methodologies.

1.2 Recommendations for Model Approaches Framework and Methodologies

The framework and methodologies for calculating the prices are based on the recommendations in this paper, which are listed below (together with references to the sections in the paper in which they are developed).

Cost categories (4.3)

Distributors should categorise their revenue requirements in terms of the following three components:

- Consumer-Specific Costs;
- Load-Dependent Costs; and
- Load-Independent Costs.

Allocating Load-Dependent Costs to Network Asset Groups (4.4)

Zones should be defined geographically for areas where the cost drivers or the characteristics of one area are significantly different from those of another area. Reasons for disaggregation should be given and the geographical areas defined – by locations, ICP numbers, supplying GXPs etc. (**4.4.1**)

Assets within a geographical area should be further disaggregated into asset groups according to their use in delivering electricity to the Load Groups. (**4.4.2**)

ORC should be used to allocate Load-Dependent Costs to asset groups. This reflects the LRAIC of providing distribution services and reduces the variability in costs according to age, smoothes maintenance cost recovery. (**4.4.3**)

Allocating Network Asset Group costs to Load Groups (4.5)

The key cost drivers to be used for allocating Network Asset Group costs to Load Groups are the Load Groups':

- Anytime Maximum Demand (AMD); and
- Coincident Peak Demand (CPD). (**4.5.1**)

Each Load Group's Anytime Maximum Demand (AMD) and Coincident Peak Demand (CPD) should be calculated or assessed as averages over 100 hours of the Load Group's Anytime Maximum Demands and Coincident Peak Demands. This number of hours may be varied by a Distributor based on its particular load duration curve. Reasons for varying should be disclosed. (**4.5.1**)

The minimum level of disaggregation to Load Groups categorises Load Groups into the following Connection Categories:

- General connections, requiring use of the LV network and all upstream (higher voltage) assets;
- Major connections, requiring use of 11kV and upstream (subtransmission) assets;
- Large Major connections, requiring use of the subtransmission network only. (**4.5.2**)

The General connections using the LV network and all upstream (higher voltage) assets may be further disaggregated into the following maximum number of Load Groups:

- up to 15kVA – this range covers most domestic and some small commercial loads with single-phase supply;
- 16kVA to 70kVA – the range covers large domestic and most commercial loads. The 70kVA breakpoint corresponds to a 100 amp fuse limit and represents an appropriate breakpoint between retail loads and larger manufacturing businesses;
- 71kVA or greater.

This is the maximum level of disaggregation proposed by PAWG given the data that is currently available. (**4.5.3**)

The level of disaggregation and the breakpoints between the Load Groups should be reviewed if a Distributor has data that indicates significantly different load profiles for a different categorisation of Load Groups. Where Distributors use load profiles to allocate costs to Load Groups they should provide transparency around the profile in order that Retailers can interpret the cost drivers correctly when they rebundle the distribution prices. (**4.5.3**)

Disaggregation by service quality should be a consideration in proposing price structures and this is noted without a firm recommendation at this time. (**4.5.4**)

Price signalling (5.2)

Congestion in networks should be signalled through dynamic Congestion Periods and dynamic demand prices where and when it is cost effective to do so – i.e. where and when the benefits of more precise price signals outweigh the costs of the equipment for dynamically notifying Consumers of when Congestion occurs. Where it is not cost effective to dynamically signal Congestion to Consumers (or impractical for Consumers to respond to dynamic price signals):

- high price periods approximating Congestion Periods should be pre-defined.
    - for winter-peaking networks, standard high price periods of 7am to 11am and 5pm to 9pm on week-days are recommended;
    - a Distributor may define different high price periods and provide the reasons for varying from the above standard bands;
    - for summer-peaking networks, the Distributor should publish the high price periods it uses to approximate Congestion Periods;
    - the high price period should be restricted to the season in which the Congestion Periods occur;
- in addition to the above high price periods, Distributors may define shoulder periods either side of each high price period;

Notwithstanding the pre-definition of high price and shoulder price periods, Distributors should also advise Consumers of periods when they do not expect Congestion to occur, and may offer Consumers guarantees that they will not face high, Congestion-related prices.

The variable charges are aimed at reflecting LRAIC. Although they are calculated by allocating the Load-Dependent Costs relating to the existing network assets, they should (on a $/kVA/year basis and over the life cycle of the assets) closely approximate the LRAIC for replacement or incremental supply to those Consumers in those geographical areas.

Model Price Structure (5.2.1)

Price structures for Large Major, Major and General connections with half hourly metering should recover the target revenues by:

- fixed prices that recover Consumer-Specific Costs and Load-Independent Costs;

- fixed capacity prices based on contract or agreed capacity (in kVA) at the connection point or the preceding year's peak demands; and
- variable Congestion Period price component charged on marginal demand that reflects LRAIC:

Price structures for General connections without half hourly or multi-rate metering should recover the target revenues by:

- a fixed price component that recover Consumer-Specific Costs, Load-Independent Costs and, if appropriate, the capacity part of the Load Dependent costs; and
- a variable average demand or consumption component using high, shoulder and low prices.

The differences between the high, shoulder and low prices, and between the variable demand prices at times of network congestion and the variable demand prices at other times, should reflect the extent to which the network or zone is congested (and hence the extent to which the Distributor wishes to encourage load control).

The actual price structure for General connections without half-hourly metering may, at least in the short term, need to be set taking into account the available metering and the need for price stability. Therefore the price options for General connections without half-hourly metering may be derived from the variable prices recommended above. For ICP pricing Distributors may use the profiles associated with meter registers to derive price structures that are consistent with those recommended above for the Major connections. The work being carried out by the Electricity Commission to simplify the rules around registration of profiles will facilitate this.

2. Introduction

2.1 PAWG Terms of Reference

The Pricing Approaches Working Group (PAWG) is a consultative group formed for the purpose of developing voluntary model approaches to distribution pricing. The group's terms of reference are to:

- *develop model approaches to distribution pricing by defining principles, methodologies and framework*
- *ensure that the terms and conditions for connection of distributed generation to networks is included within the model distribution pricing methodology and that these terms and conditions are subject to dispute resolution under new rules*
- *consider and use, where appropriate, work done by Model Distribution Arrangements Project (MDAP) sub-group.*
- *establish robust process for stakeholder identification and consultation.*
- *comply with all relevant legislation*

The work is being undertaken recognising

- that Part 4A of the Commerce Act may introduce additional governmental requirements that will need to be considered
- the uncertainty of future Transpower pricing and contractual arrangements

PAWG has adopted the Guiding Principles for distribution pricing previously developed by the Model Distribution Arrangements Project (MDAP) established under MARIA that:

- *prices should encourage efficient investment and technology innovation in the provision of distribution services;*
- *prices should not create inefficient barriers to entry in the market for distribution services;*
- *prices should not unjustifiably discriminate between Retailers/Consumers of the Distributor;*
- *prices should encourage the efficient use of distribution services;*
- *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;*
- *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*
- *prices should satisfy legal and regulatory requirements*

2.2 Purpose of this paper

This paper addresses one of the key tasks of PAWG which is to "develop model approaches to distribution pricing by defining principles, methodologies and framework." It is a revised version of Discussion Paper No 2[1] dated 3 August 2004. Revisions have been made to incorporate feedback from a seminar held in Wellington on 25 August 2004 and written submissions that were subsequently received from interested parties.

A presentation was made to the Electricity Commission immediately following the 25 August seminar. The purpose of the paper is to inform the Electricity Commission of the work completed by PAWG so that it may assist the Electricity Commission in carrying out its regulatory functions in relation to distribution pricing as set out in the most recent Draft Government Policy Statement of September 2004 and specifically the requirement that:

"The Electricity 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."

It is envisaged that future work in the development of distribution pricing principles and/or model approaches will be undertaken by the Electricity Commission.

[1] The 3 August 2004 Discussion Paper was the second discussion paper produced by PAWG. The first was issued on 23 May 2003.

3. Overview of Current Approaches

The current methodologies have been developed (or in some cases evolved) under "light-handed" regulation, which requires Distributors to publicly disclose the methodologies they have used to calculate prices.

3.1 Disclosure of Price Methodologies

The Electricity (Information Disclosure) Regulations 1999 require Distributors to[2]:

(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 line owner's line business activities, including the 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 line owner 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*

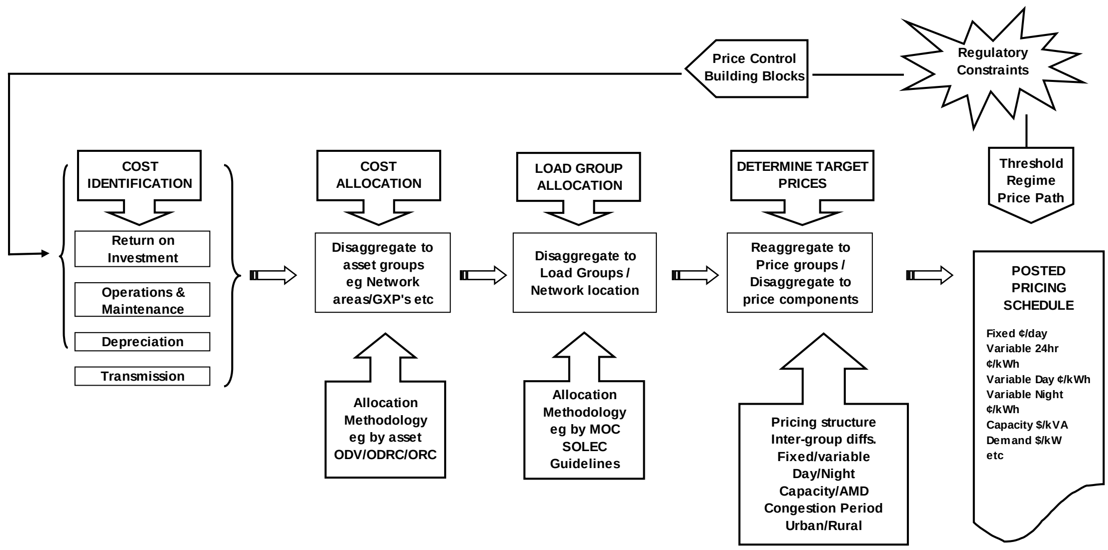
(d) *Describe the method by which the line owner allocated the components of the revenue required to cover the costs of its line business activities amongst Consumer groups, which must include the numerical values of the different components allocated to each Consumer group and the rationale for allocating it in this manner; and*

(e) *Describe the method by which the line owner determined the proportions of its charges which are fixed and the proportion which are variable, and the rationale for determining the proportions in this manner.*

The regulations do not prescribe the methodology to be used and a diverse range of methodologies have been developed. The key steps in the pricing process, which includes cost allocation inputs to the pricing methodology, are illustrated in Figure 1 below.

2 Regulation 24 of the Electricity (Information Disclosure) Regulations 1999, and as amended in 2000 and 2001. The same requirements are contained in Part 5 of the draft Electricity Information Disclosure Requirements 2004 released by the Commerce Commission 24 December 2003

Figure 1: Cost Allocation/Pricing Methodology Process



Under Part 4A of the Commerce Act a Distributor's prices and revenue are subject to regulatory constraints. Its prices may be constrained by the price path threshold set by the Commerce Commission or by a declaration of control by the Commerce Commission following a breach of the price path threshold. The price threshold is based on the structure of a Distributor's prices (and not, for example, on a set c/kWh value). Hence the structure relates closely to regulatory risk selected by the company's Board and management.

The regime identifies pass-through costs (viz. transmission costs, Electricity Commission levies and local authority rates) which may add further influences to the process of allocation. Therefore the "costs" referred to below and throughout this paper are the amounts that may be recovered subject to the constraints imposed by regulatory regime.

The steps shown in Figure 1 for calculating prices are:

1. cost identification – This determines the total costs of providing distribution services, including a return on investment, depreciation, operating and maintenance costs and overhead costs. This sets a total revenue target, which is then disaggregated according to the different nature of the costs. The two main categories of costs are those that depend on the load supplied by the Distributor, and those which do not.

2. allocating Load-Dependent Costs to asset groups – The Load-Dependent Costs are the direct costs of providing, operating and maintaining the network assets. To reflect the different costs of providing distribution services to loads in different parts of the network, the network assets may be disaggregated to asset groups – e.g. into geographical areas (by specifying the area and/or the grid exit points supplying the network in the area and/or the ICPs supplied from the network in the area), by

defining different service levels and by the different voltage levels at which loads are supplied.

3. allocating costs to Load Groups – The asset group cost allocations are then allocated to Load Groups. The Load Groups are defined by the Distributor according whether they have different impacts on the costs. The allocation of costs to Load Groups determines the target revenue to be recovered from each Load Group. The parameters used to carry out the allocation are those considered to be the main cost drivers.

4. determining target prices – The target revenue for each Load Group is converted into target prices, using the Distributor's price structure. The aim is to provide efficient price signals to Load Groups which will generally reflect the main network cost drivers. The Distributor's local knowledge will influence the final shape of the prices. Factors taken into account include
   - the optimal mix of continuous versus controllable load that can be encouraged;
   - other load characteristics; and
   - available metering

The prices will reflect the level of averaging or pricing transparency that can be tolerated or is desirable. Regulatory constraints will also influence the prices.

3.2 SOLEC Report

Distribution prices were first introduced following the separation of line and energy charges in 1993. A report by the Separation of Line and Energy Charges (SOLEC) Working Party[3] proposed six Consumer groups based on their use of various network components and their capacity requirements:

- general 230/400V supply capacity ≤ 15kVA
- general 230/400V supply capacity > 15kVA
- dedicated 400V supply > 15kVA
- general 11kV supply
- dedicated 11kV supply
- dedicated networks supply voltage ≥ 11kV

The SOLEC report also suggested that some groups could be further subdivided – e.g. the first group could be broken down by capacity of < 1kVA, 1 – 8 kVA and 9 -15 kVA - and that: major users could be separated from other large industrial users; users on spurs separated

[3] "Guide to the Derivation of Line Charges" report by the SOLEC Working Group January 2002

from meshed network users; and users classified as urban, rural or remote rural according to load density.

3.3 Overview of Current Methodologies

3.3.1 Distributor Business Models

The two different Distributor business models[4] currently used are:

- Wholesale Delivery Model, in which quantities reconciled at the GXPs are used for calculating prices payable by the Retailer; and
- Retail Delivery Model, in which quantities metered at the ICPs are used for calculating prices payable by the Retailer; or Consumer.

In practice, neither model 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 example shown in Annex 3).

One of the main differences between these two approaches relates to the party responsible for determining the load shape or profile of a connection. In the Wholesale Delivery Model, the only process currently available for determining the load profile of a connection is that of the Reconciliation Process. The Reconciliation Process was designed for the half-hourly purchase of electricity and provides load profiles for all loads that purchase electricity half-hourly and a residual profile of all other electricity purchases. Retailers may also submit load profiles to the Reconciliation Manager for inclusion in the Reconciliation Process.

In the Retail Delivery Model, the load profile is determined by the Distributor and can include any data that the Distributor considers relevant – e.g. maximum demand.

It is possible to have a business model that uses elements from both the Wholesale and Retail Delivery Models. In the Wholesale Delivery Model as currently practised most Distributors apply ICP pricing to the half-hourly metered Major and Large Major Consumers, particularly where there is risk of bypass and where dynamic Congestion Period-based pricing can be effective. The half-hourly metered data for these connections is adjusted in the Reconciliation Process by the distribution loss factors to give the corresponding GXP data for charging the Retailers. The aggregate demands of the General connections are then calculated as the difference between the loss-adjusted Major and Large Major connections' demands and the GXP metered data and allocated to Retailers through the Reconciliation Process. This process minimises the Distributors' exposure to both technical and non-technical losses risk. Enhancement of this allocation could be achieved by utilising half-hourly

[4] The Wholesale Delivery Model is also referred to as a GXP pricing approach, and the Retail Delivery Model as an ICP pricing approach

metering information, where this is available for Consumers in the General connections category, or other Consumer information, such as consumer types or deemed load profiles[5].

In a pure Wholesale Delivery Model, the reconciled GXP data would provide the full set of data required to calculate wholesale distribution prices. However, using GXP data only would not capture the Consumer-Specific Costs so in practice a mixed delivery model is needed. Fixed charges per ICP applied by the Distributor are also the only means of the Distributor to directly signal to Consumers supplied from the same GXP any different service quality levels, demand side management capability or capacity levels. Signalling to domestic Consumers through these fixed prices per ICP is constrained by regulation.

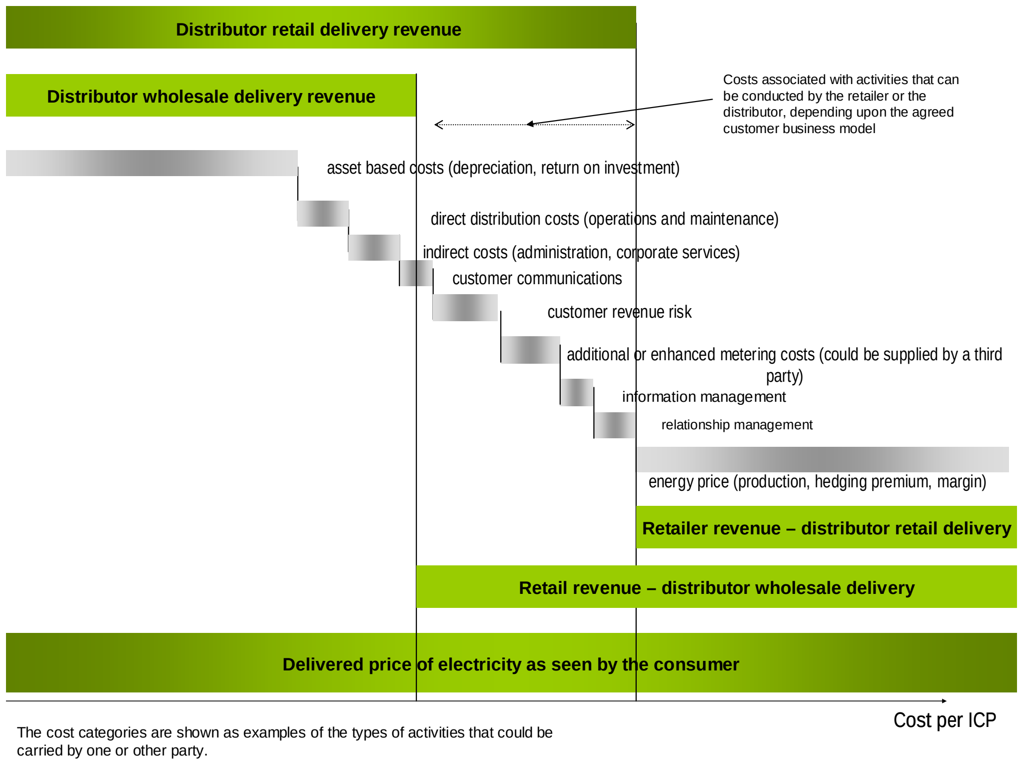
Another potential difference between these two approaches is that they may result in different distribution costs (and hence revenue requirements) as a result of the differences in the breakdown of activities between the Distributor and the Retailer. In the Wholesale Delivery Model, the Distributor charges Retailers for the use of the network based on each Retailer's offtake calculated at the GXPs. In the Retail Delivery Model, the Distributor calculates prices for end use Consumers and each Retailer's charges are the aggregate of its end use Consumer charges. In the Wholesale Delivery Model, the Distributor is able to avoid some costs by leaving the Retailer to carry out functions that could be carried out by either of them. Compared to the Wholesale Delivery Model, the additional costs likely to be incurred by the Distributor under the Retail Delivery Model include:

- higher administration costs, including the costs of developing more detailed pricing structures;
- additional information management costs – e.g. of Consumer databases; and
- Consumer communications and relationship management costs.

The two Distributor business models and the potential cost differences are illustrated in Figure 2.

5 These enhancements would, however, use Consumer information and move the Wholesale Delivery Model pricing closer to Retail Delivery Model pricing.

Figure 2: Distributor business models



It should be noted that Figure 2 represents extremes in the breakdown of functions between Distributors and Retailers. In practice, the functions carried out by the Distributor and the Retailer will depend on the contractual arrangement between them.

The choice of Distributor business model also affects the extent to which Distributors disaggregate their costs and set different prices for different Load Groups.

3.3.2 Cost categorisation

The distribution costs are described differently by different Distributors but generally fall into one of three broad categories:

- costs in providing equipment or services specifically for a connected party;
- costs that are directly related to providing network capacity to meet demand on the network, including depreciation of and a return on the network assets, and direct operating and maintenance costs; and
- other costs that are not directly related to network capacity, such as the cost of non-network assets (including depreciation and a return on those assets), and administrative and corporate overheads.

The distinction between these two types of costs is made to enable the Load Dependent Costs to be recovered more efficiently, by reflecting those costs in load dependent prices to influence network usage by changing Consumers' behaviour, and to recover the other Load-Independent Costs in as neutral a manner as possible.

3.3.3 Allocating costs to Asset Groups

Where Distributors provide dedicated network assets, e.g. a dedicated transformer to supply a major user, the costs associated with the dedicated assets are usually separated from general network assets costs and allocated directly to the user. This enables Distributors to directly signal the costs of providing dedicated assets and makes the provision of such assets potentially more contestable.

The shared network costs, which recover return on assets, and depreciation and maintenance costs, are allocated to assets groups within the network. The current disaggregations to asset groups include:

- geographical areas that are supplied from a particular GXP, a group of GXPs, zone substations or feeders; and/or
- supply voltage level; and/or
- areas with different load characteristics – e.g. summer- or winter-peaking, low or high user density (including urban/rural type separation).

Disaggregation by geographical area can better reflect the costs of providing distribution services to Consumers in different parts of the network, particularly in larger networks. Current disaggregations into geographical areas or zones generally tend to reflect the sizes of the networks and the extent to which separate zones have different characteristics:

- Larger networks tend to be divided into areas associated with particular GXPs, creating zones within the network. For example, distribution businesses with total system lengths[6] of 7,000 km and above (e.g. Vector, Powerco and PowerNet) disaggregate their networks into zones (usually associated with particular GXPs).
- Small networks with total system length of less than 3,500 km (e.g. Ashburton, Buller, Counties Power, Electra, Mainpower, Marlborough, Nelson, Scanpower, Tasman, Waipa and Westpower) do not disaggregate their networks into zones.
- Eastland classifies its 11kV feeders and disaggregates its network assets according to whether they are in high-, medium and low-density areas.
- Vector, in its Auckland network, has established zones around the denser industrial regions in close proximity to GXPs.

[6] The system lengths are taken from the Ministry of Economic Development Statistics for 2001

Disaggregation by voltage level is aimed at ensuring that Consumers pay only for the parts of the network they are using. Distribution assets are disaggregated into:

- subtransmission assets (33kV and above);
- zone substations;
- HV distribution assets (typically 11kV, but including all assets above 400V and less than 33kV);
- distribution substations; and
- LV distribution assets (400/230V)
- dedicated equipment
- other equipment, specifically dedicated to one or more Consumer groups (e.g. pilot wire control circuits that are used by street lighting and domestic loads)

Most Distributors disaggregate their network assets by voltage level as proposed in the SOLEC report.

Various approaches to disaggregating networks into Network Asset Groups and allocating costs to those asset groups are currently used. These include one (or, in some cases, more than one) of the following:

- Optimised Replacement Cost (ORC);
- Optimised Depreciated Replacement Cost (ODRC); or
- Optimised Deprival Value (ODV).

ODV and ODRC differ only if an economic value assessment has determined an ODV that is lower than the ODRC.

3.3.4 Allocating costs to Load Groups

The costs that have been allocated to Network Asset Groups are then allocated to the Load Groups supplied by them. The Load Groups are defined in a number of ways, including by:

- connection category – e.g. by supply voltage level;
- load characteristics – e.g. by installed capacity at the load's point of connection;
- market segment – e.g. domestic, commercial, industrial etc.

Some of these definitions may be used in combination. The current classifications of Consumers into load and/or pricing groups are aimed at identifying groups that use different asset groups and whose load characteristics impose different capacity requirements on those asset groups. The main[7] Load Groups currently used by Distributors include:

- residential/domestic Consumers, which generally fall into a single group but may be further classified according to connection capacity (8kVA and 15kVA or 20kVA) or type of network (urban or rural).
- non-domestic, which includes most other Consumers;
- large commercial or industrial users;
- irrigation; and
- major users.

Numerous further classifications of Load Groups within the above categories are also used. These include by voltage, fuse size, installed connection capacity (kVA), annual energy consumption (kWh). Since load characteristics tend to vary with the size of the Consumer load (as measured by installed connection capacity), installed connection capacity is used by some Distributors to specify Load Groups. The breakpoints chosen vary between Distributors – e.g. one Distributor has ranges above 15 kVA with breakpoints at 30, 50, 75 and 100 kVA, another has a lower boundary 20 kVA and breakpoints at 30, 70 and 140 kVA and another puts all Consumers in a 16-149 kVA range within a single Load Group.

The Load Group parameters that are currently used by Distributors to allocate Load-Dependent Costs include:

- 50% by Load Group Anytime Maximum Demand and 50% by Congestion Period demand;
- subtransmission (and transmission) costs on Anytime Maximum Demand and lower voltage asset costs on a different basis;
- connection capacity;
- 3 year rolling averages of Coincident Peak Demand; and
- Coincident Peak Demand for some Load Groups and peak demand at Consumer installation for other Load Groups

Load Groups may also be differentiated on the basis of service level (as is currently the practice by Vector). In this case, costs and prices are averaged across a wide rural/urban area but the cost of service provision is defined by Consumer service level commitments. Thus lower costs are achieved and margins maintained in higher cost rural areas by setting targets that allow higher outage incidence and longer outage duration.

[7] There are also special load categories such as street lighting, irrigation and unmetered temporary supplies that may need to be added to the broader load groups considered here.

3.3.5 Price components

The allocated costs are recovered by setting prices that are aimed at reflecting the costs of providing distribution services. Dedicated equipment prices generally relate to the specific costs relating to transformers, switchgear, substations/kiosks and metering equipment dedicated to the Consumer and are set as prices for specified ranges of transformer sizes, etc.

For the shared network assets, most Distributors base their prices for each Load Group on the Network Asset Group costs that have been allocated to the Load Group. An alternative approach, used by Orion, is to calculate the Long Run Incremental Cost (LRIC) of expanding the network to meet the demands of the Load Groups (which in this case correspond to i) connection categories at the different supply voltages, and ii) street lighting). The LRIC-based prices are supplemented by additional price components that make up any shortfall between the LRIC prices and the total revenue requirement.

The various types of price components currently used by Distributors, and the objectives to which they relate, are summarised in the following table.

Table 1: Current price components

Objective	Price component(s)
Directly recover costs of dedicated equipment	Connection charge – ($/ICP) Specific charge for dedicated equipment ($/item) Capacity-based connection charge – ($/installed kVA)
Reflect cost of providing the existing network Signal the LRIC[8]	Maximum demand charge – ($/kW or $/kVA) Congestion Period charge – ($/kW or $/kVA maximum demand (or average demand during a Congestion Period) Connection charge – ($/installed kVA) Distance charge ($/installed kVA-km) Differential consumption charges (c/kWh) for different time periods – e.g. summer/winter, day/night Differential charges (c/kWh) according to whether load is controllable Differential connection charge ($/ICP) according to whether load is controllable
Signal the need to improve power factor	Voltage support charge ($/kVAr)
Recover balance of revenue	Connection charge – ($/ICP) Variable charge (c/kWh) Variable charge ($/kW or $/kVA maximum demand for average demand during a defined Congestion Period)

3.4 Concerns with Current Distribution Price Methodologies

Concerns expressed by Retailers’ and Consumers’ representatives are summarised in Annex 1. Not all of the concerns expressed are shared by all Retailers and all Consumers.

Some of these concerns are not direct consequences of the distribution price methodologies. However, the development of a more transparent model approach with greater consistency between distribution networks may enable them to be more readily addressed.

8 Orion

4. Inputs to Developing Model Approaches

In developing model approaches PAWG considered the application of the Guiding Principles and in particular the price signals needed to meet the efficiency objectives. Alternative approaches, drawing on Distributors' current pricing approaches and practices, were assessed.

The Guiding Principles set out high level objectives for efficient investment in, and use of, distribution networks. However they are also aimed at promoting retail competition and innovation by Distributors. Therefore the efficiency objectives need to be balanced against the costs of implementation and the ability and incentives of the relevant parties to respond to price signals.

The options are further constrained by Government policy and regulation. The thresholds regime implemented by the Commerce Commission from 1 April 2004 aims to limit annual movements in prices. The Government has introduced regulations[9] requiring retailers to offer low fixed charge tariff options of no more than 30cents/day to domestic consumers and distributors to offer distributor tariff options (to retailers or directly to consumers) at a maximum of 15cents/connection/day.

4.1 Efficiency Issues

In its 23 May 2003 draft consultation paper[10] PAWG did not address in detail the theoretical economic arguments on distribution pricing. However it recognised the importance of dynamic efficiency, in sending the right signals for new investment, consumption levels over time and encouraging innovation.

PAWG received a paper[11] in the consultation process and was referred to a further paper[12] that both argued, on economic efficiency grounds, for distribution pricing that reflects some form of marginal or incremental cost. PAWG requested LECG to review these papers and advise as to how best to reflect these issues relating to economic efficiency in the model approaches, taking into account practical implementation issues.

LECG advised that[13]:

"Given practical issues that must be resolved in pricing in the context of electricity distribution, prices that aim to reflect the incremental cost to supply the service will generally reflect some

9 Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004, effective 1 October 2004

10 "Model Approaches to Distribution Pricing" Draft Consultation Report prepared by the Pricing Approaches Working Group 23 May 2003

11 "Model Approaches to Distribution Pricing", submission to PAWG prepared by Charles Rivers Associates

12 "Reducing Regulatory Barriers to Demand Management" Sinclair Knight Merz and M-co, November 2003

13 "Incremental cost measures and pricing" a paper prepared by LECG for PAWG, 21 June 2004

form of long run average cost to supply the service, or a form of long run incremental cost that is defined in such a way as to be equivalent."

Thus PAWG has adopted in the model approaches the long run average incremental cost (LRAIC) standard for reflecting incremental costs in prices. The LECG paper is attached as Annex 4.

The LRAIC is calculated from considering the incremental cost over the life cycle of the network assets to provide the capacity to distribute to the existing maximum load. This calculation involves consideration of the annualised Load-Dependent Costs, generally calculated as the Optimised Replacement Costs (ORC) of the assets multiplied by an annual capital recovery factor plus the annual operating and maintenance costs.

4.2 Overview of Price Setting Process

The process for setting prices follows the basic steps outlined below:

- cost allocation;
- price setting for load profiles, using half hour periods to define each load profile (as this matches current market and metering practices). This should be carried out consistently for all Load Groups.
    - for the Wholesale Delivery Model, prices are set using the profiling done by the Reconciliation Process ;
    - for the Retail Delivery Model, the Distributor needs to form load profiles from each meter function to obtain prices per unit for each meter.

PAWG noted the differences in the process for setting prices between the alternative Wholesale Delivery and Retail Delivery Models. While it recognised that there are also differences between the two models in terms of the amount of the indirect costs borne by the Distributors and the categorisation of Load Groups, the key question as to whether one approach is preferred over the other depends on the extent to which they are able to meet the Guiding Principles. Most steps in the cost allocation and pricing processes are common to both approaches and, where the two approaches differ, the differences are identified in this paper.

4.3 Cost categories

As in the current approaches the total revenue requirement is first broken down into three different cost categories:

- Consumer-Specific Costs ;

    The costs of dedicated equipment and services should be separately identified so that consumer-specific costs are recovered from those Consumers. The provision of consumer-specific equipment may be contestable. Such equipment could be owned by the Consumer, or a third party, instead of the Distributor. In many cases, however, dedicated equipment will be owned by the Distributor with dedicated use by a Consumer or group of Consumers. Dedicated services are, by definition, specific to the Consumer and are over and above the services normally supplied to all network Consumers.

- Load-Dependent Costs .
    - These include the costs of operation and maintenance of the shared network assets, and depreciation and post-tax return on those assets;
    - The Load-Dependent Costs of the shared network assets are driven by the demands on the network and should be allocated in a way that allows the costs to be signalled to Consumers.
- Load-Independent Costs.
    - The Load-Independent Costs relate to the business running costs and the costs of non-network assets and include the costs of administration, system operations, depreciation and return on IT and other non-network assets, and regulatory compliance costs and levies..

It is recommended that:

Distributors should categorise their revenue requirements in terms of the following three components:

- ***Consumer-Specific Costs;***
- ***Load-Dependent Costs***
- ***Load-Independent Costs.***

PAWG notes that most Distributors currently categorise their costs in these terms and does not propose to prescribe a methodology for carrying out this categorisation.

It should be noted that the Load-Dependent Costs might not increase in direct proportion to load. There are economies of scale and some asset costs that make up part of the Load-Dependent Costs that are not strictly load-dependent – e.g. poles, which over a range of conductor sizes, do not change with line capacity. The average age of the assets may be reflected in the overall revenue calculation so revenue recovery based on ORC allocations may, at a particular point in time, be greater or less than the LRAIC.

4.4 Allocating Load-Dependent Costs to asset groups

The allocation of Load-Dependent Costs, and setting prices to recover those costs, are the most complex aspects of distribution pricing. As noted above, the recovery of the Load-

Dependent Costs relating to the existing network should reflect the long run average incremental cost (LRAIC) of maintaining, replacing and expanding the network. These costs will vary between different parts of the network, depending on the cost of the assets in each part, including the high voltage (HV) and low voltage (LV) parts.

PAWG proposes a systematic approach for disaggregating network costs to asset groups. To a large extent the approach follows current practice, which disaggregates networks into asset groups where there are material differences in costs.

4.4.1 Disaggregation of assets by geographical areas

The current practice of disaggregating networks into zones should be part of the model approach but a more consistent and transparent approach needs to be taken. To provide transparency, disaggregation of a network into geographic areas needs to be supported by the reasons for disaggregating – e.g. separable and significantly different costs, different cost drivers and/or different load characteristics, different distribution distance and different service quality. The zone needs to be defined – e.g. by geographic area, by ICP numbers of ICPs within it, by the GXP(s) supplying it.

It is recommended that:

Zones should be defined geographically for areas where the cost drivers or the characteristics of one area are significantly different from those of another area. Reasons for disaggregation should be given and the geographical areas defined – by locations, ICP numbers, supplying GXPs etc.

Although disaggregation by geographical area carried out for the Wholesale Delivery Model will be limited to each GXP-supplied area, the disaggregation by area should be carried out as the approach is aimed at signalling the LRAIC of supplying loads at different locations (and times).

4.4.2 Disaggregation of assets by voltage level/use of assets

Within each zone/geographic area, there should also be a disaggregation to the different voltage asset groups. This ensures that users will not be allocated costs of downstream assets (e.g. lower voltage) that they do not use.

It is recommended that:

Assets within a geographical area should be further disaggregated by use of assets where the Distributor has users taking supply from a connection to a network that does not involve further downstream voltage asset classes (see following table).

Table 2: Disaggregation to asset groups by use of assets/supply voltage

Asset Groups	User Connection Categories		
	LV users	**11 kV users**	**Subtransmission users**
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

4.4.3 Assigning Load-Dependent Costs to asset groups

After disaggregating the network assets to Network Asset Groups – by geographical area and/or voltage level/use of assets – the Load-Dependent Costs need to be allocated to each asset group. For information disclosure, network assets are currently valued using the Optimised Deprival Value (ODV) methodology. In calculating the ODV, Optimised Replacement Cost (ORC) and Optimised Depreciated Replacement Cost (ODRC) are also calculated.

The two options considered to allocate Load-Dependent Costs :

- allocating post-tax return and depreciation on ODRC and actual maintenance costs; or
- allocating all direct network costs, including maintenance costs, on ORC.

The allocation of Load-Dependent Costs on the basis of ORC reflects the LRAIC (refer to the definition of LRAIC in section 4.1).

The effect of allocating on ORC rather than ODRC is that ODRC reflects the ages of the assets, while ORC smoothes out variations in costs due to different asset ages (and maintenance cost profiles where maintenance costs are also allocated on ORC). Allocating costs on the basis of ODV (or ODRC) would result in allocated costs declining as assets aged (partly offset by rising maintenance costs), followed by substantial rises when the assets are replaced.

It is recommended that:

ORC should be used to allocate Load-Dependent Costs to asset groups to reflect the LRAIC of providing distribution services. This also has the effect of reducing the variability in costs due to age and maintenance costs.

It should be noted that ORC is used to <u>allocate</u> costs and does not necessarily reflect the actual costs faced by a Distributor.

4.5 Allocating Network Asset Group costs to Load Groups

Different loads can have different impacts on load-dependent network costs. To allocate costs to different loads or Load Groups, first it is necessary to identify the key cost drivers and then to use those key cost drivers to define and allocate costs to Load Groups.

4.5.1 Key cost drivers

The key cost drivers for network investment are the maximum or peak loadings on the network assets. At and close to the point of connection of a load to the network, the main cost driver is the Anytime Maximum Demand. For assets that are shared between several Load Groups, diversity between Load Groups means that the loading on the network is less than the sum of the Load Groups' Anytime Maximum Demands and the Coincident Peak Demands become the main cost driver. Distributors therefore plan their networks on the basis of both Anytime Maximum Demands and Coincident Peak Demands.

It is recommended that:

The key cost drivers to be used for allocating Load-Dependent Costs between Load Groups are the Load Groups':

- ***Anytime Maximum Demands (AMD); and***
- ***Coincident Peak Demands (CPD).***

The periods for calculating AMD and CPD need to be defined. The demands over a single half-hour peak period do not drive investment, rather the demands are measured and averaged over number of peak periods. The number of periods that need to be considered in network expansion planning varies between networks, depending on the shape (steepness) of the load duration curve near the system peak. Based on current planning practices, around 100 hours (or around 1% of the year) is considered appropriate.

It is recommended that:

Each Load Group's Anytime Maximum Demand (AMD) and Coincident Peak Demand (CPD) should be calculated or assessed as averages over 100 hours of the Load Group's Anytime Maximum Demands and Coincident Peak Demands. This number of hours may be varied by a Distributor based on its particular load duration curve. Reasons for varying should be disclosed.

It should be noted that this number of periods relates only to the allocation of costs between Load Groups and that the periods are not necessarily the same as the periods used for pricing.

4.5.2 Disaggregation to Load Groups by Connection Category

The disaggregation of network assets into asset groups as set out in section 4.4.2 establishes a minimum categorisation of Load Groups. This categorisation, which ensures that Load Groups are not allocated costs of assets which they do not use, is the minimum Load Group categorisation. PAWG agrees that this level of disaggregation is necessary for an efficient and equitable allocation of costs.

It is recommended that:

The minimum disaggregation into Load Groups categorises Load Groups into the following Connection Categories:

- ***General connections, using the LV network and all upstream (higher voltage) assets;***
- ***Major connections, using 11kV and upstream (subtransmission) assets;***
- ***Large Major connections, using the subtransmission network only.***

There may be further disaggregation into special category Load Groups, such as streetlighting, irrigation and temporary supplies .

4.5.3 Disaggregation by Load Group characteristics

Further disaggregations into additional Load Groups should also be considered where different Load Groups can be identified as having significantly different impacts on network costs. Since the impacts of different Load Groups on costs are driven primarily by their Anytime Maximum Demands and Coincident Peak Demands, this requires Load Groups with significantly different diversity factors to be distinguished.

Loads greater than 350kW are metered half-hourly so the Anytime Maximum and Coincident Peak Demands are directly measurable. These loads may be disaggregated into Load Groups with different diversities. Where loads are not metered half-hourly, the Anytime Maximum and Coincident Peak Demands are estimated using each Load Group's load profile, representative load profiles can be calculated by metering statistical samples of users in the various Load Groups.

In further disaggregating Load Groups there is a need to strike a balance between the complexity of achieving greater efficiency and equity in cost allocation (and pricing) on the one hand and practicality on the other. This balance should be based on the materiality of the differences in load characteristics that lead to differences in prices.

Based on the above considerations and current practice in New Zealand it is recommended that:

The General connections using the LV network and all upstream (higher voltage) assets may be further disaggregated into the following maximum number of Load Groups:

- ***up to 15kVA – this includes most domestic and some small commercial loads with single-phase supply;***
- ***16kVA to 70kVA – the 70kVA breakpoint includes loads using the LV network with a 100 amp fuse limit and represents an approximate breakpoint between retail loads and larger manufacturing businesses;***
- ***71kVA or greater.***

This is the maximum level of disaggregation recommended by PAWG given the data that is currently available.

It is recommended that:

The level of disaggregation and the breakpoints between the Load Groups should be reviewed if a Distributor has data that indicates significantly different load profiles for a different categorisation of Load Groups. Where Distributors use load profiles to allocate costs to Load Groups they should provide transparency around the profile in order that Retailers can interpret the cost drivers correctly when they rebundle the distribution prices.

It is noted that an industry working group is developing improved rules on the use of load profiles for individual connections and these are likely to assist Distributors in the future to refine their prices so that they better reflect the costs imposed by loads without half-hourly metering.

A lowering of the limit (currently 350kW) at which half-hourly metering becomes mandatory in the New Zealand electricity market would also contribute to better price signalling.

In the Retail Delivery Model, the Distributor carries out the further disaggregation into Load Groups in order to signal different distribution costs to different Load Groups. The distribution prices are charged to Retailers in a form that can be directly passed onto Consumers or, alternatively, could be charged directly by Distributors to Consumers. Consumers may then respond to price signals provided by the Distributor to minimise their costs and in doing so also minimise the Distributor’s costs.

The application of the process for allocating costs according to Load Groups' (or Connection Categories') Anytime Maximum Demands and Coincident Peak Demands is illustrated in Annex 2.

In the Wholesale Delivery Model, Load Groups are disaggregated only to the minimum level (refer section 4.5.2) of the Connection (and special Load Group) Categories. Retailers are charged by the Distributor for wholesale delivery only and must decide how to recover their wholesale distribution costs from Consumers, including whether to disaggregate Consumers into smaller groups so that they (the Retailers) can minimise their wholesale delivery costs.

In the Wholesale Delivery Model, Load Groups could be disaggregated by the Distributor if ICP based fixed charges are applied but this would be limited by the constraints of applying variable energy usage patterns (profiles) to fixed charges.

4.5.4 Disaggregation by service quality

Within the above Load Group categories, further Load Groups may be defined based on service quality (as is currently the practice by Vector). Where there are both rural and urban loads within an area, the costs can be averaged over the area but urban and rural Load Groups distinguished by different Consumer service level commitments. The otherwise higher costs of supplying rural loads are offset by setting targets that allow higher outage incidence and longer outage duration for rural loads.

In the Retail Delivery Model, different service quality levels can be distinguished for specific Consumers or groups of Consumers. In the Wholesale Delivery Model, different service quality levels for connections without half-hourly metering can only be distinguished at the GXP level or if ICP based fixed prices are applied then there is scope (subject to regulatory constraints) to differentiate for service quality.

5. Model Price Structures and Prices

The preceding chapter sets out a methodology to allocate costs by firstly categorising the costs – as Consumer-Specific Costs, Load-Independent Costs and Load-Dependent Costs – and then allocating those costs - Consumer-Specific Costs to those Consumers, spreading Load-Independent Costs across all Consumers and Load-Dependent Costs according to Load Groups' AMD and CPD.

This chapter develops pricing structures that achieve revenue requirements (subject to price regulation), provide efficient price signals, reflect shared costs equitably, allow innovation (in metering and retail electricity pricing) and are practical to implement.

5.1 Efficient price signals

In order to encourage efficient investment in and use of the network, when the network is congested prices should provide incentives to choose the most economic alternative – either by reducing demand, through load shifting, use of alternative energy sources or continuing to use the network if the costs of the alternatives are higher than the congestion costs.

In its submission to PAWG, Orion provided a report[14] prepared by Charles River Associates (CRA) which set out the basis for calculating efficient price signals:

"In theory, a system of nodal prices on the distribution network would provide an accurate price signal of using the distribution network at each location and at each point in time reflecting the state of the network and demand and supply. In principle, expectations of loss and constraint rentals that would arise from nodal pricing provide the correct signals for investment to mitigate the cost of losses. Nodal prices would reflect the quality and capacity of investment in the network and patterns of demand. However, nodal pricing is unworkable at the scale of a distribution network with thousands of network off-take points and injection points, but it provides a useful reminder that any other distribution pricing approach is only an approximation to the theoretical set of prices that would emerge from nodal pricing.

The practical challenge to the industry is to discover a workable approximation to this theoretical benchmark, while maintaining revenue adequacy."

Theoretically then, investment in a distribution network should be driven by nodal prices or more specifically the nodal price differences between the connection points in the network – i.e., between the GXPs and the ICPs. Since it is clearly impractical to calculate nodal prices at every point in a distribution network for every half hour, it is necessary to calculate an average price over both location and time.

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[14] "Model Approaches to Distribution Pricing: Discovering Optimal Contracts", Charles River Associates, 14 September 2004

The disaggregation of a network into geographical areas (in section 4.4.1) and the disaggregation of network assets by use of assets (in section 4.4.2) provide the locational differentiation for distribution from a GXP to points within a distribution network. Compared to the theoretical benchmark, these disaggregations lead to prices that approximate the locational price components and in effect average them over the ICPs connected to each asset group in each geographical area.

The price signals should also vary in time, to signal when there is congestion in the delivery of electricity to Consumers. The prices during the Congestion Periods should reflect the costs of investing in a network upgrade to avoid Congestion – i.e. they should reflect the LRAIC of increasing network capacity at each location (noting that “location” has been defined in terms of connections to an asset group in a geographical area). When there is no congestion, prices should have no (or little as possible) effect on Retailers’ or Consumers’ behaviour.

Ideally then, prices should include a component that signals LRAIC during the Congestion Periods and a component that ensures revenue adequacy, but does not influence Consumers’ behaviour, at all other times. Typically this ideal is achieved by multi-part tariffs, in which one part is fixed (and so does not influence Retailers’ or Consumers’ usage decisions) and the other part variable. In practice, fixed prices have some degree of variability (or avoidability); for domestic Consumers, the exclusive use of fixed prices is prohibited by regulations.

The variable price components reflecting LRAIC will be expressed in $/kVA/yr. They should recover the Load-Dependent Costs previously allocated to Consumers in each asset group in each geographical area. The prices will be different for each geographical area; it will also be different for each asset group (as shown in Table 2 of section 4.4.2). Although these price components have been calculated by allocating the Load-Dependent Costs relating to the <u>existing</u> network assets, they should (on a $/kVA/year basis) closely approximate the LRAIC for replacement or incremental supply to those Consumers in those geographical areas. As discussed in section 4.3, they may differ from LRAIC at any particular time but over the life cycle of the assets, the annualised $/kVA values will be the same (or very similar).

The way in which prices are used to send efficient pricing signals depends on the Distributor business model. In the Wholesale Delivery Model prices are aimed at providing incentives for Retailers to reduce their (wholesale) distribution costs (through the Retailers in turn providing incentives for Consumers), while in the Retail Delivery Model, prices are aimed at providing incentives directly to Consumers to reduce their (retail) distribution costs. Both approaches are, however, aimed at reflecting LRAIC when and where a network is becoming congested but lead to two different model price structures.

5.2 Price structures

The general form of an efficient price will include:

- a fixed price component, which recovers Consumer-Specific Costs and may include further fixed price components based on the installed or contract capacity;
- a variable price component aimed at signalling Congestion in the network and reflecting the cost of expanding the network to relieve the Congestion. It will therefore be a price that applies to marginal demand.

For the variable price component aimed at signalling Congestion[15], PAWG considered a range of options, shown in Table 3 below.

Table 3: Pricing options for signalling Congestion

	Signal to consume or not consume		Consumption elected by	Quantities	Measured as	Price
	Price	**Congestion Period**				
Congestion signal	Dynamic	Dynamic	Consumer	kVA	Half-hour demand	$/kVA
	Posted	Dynamic	Consumer	kVA	Half-hour demand	$/kVA
	Posted	Posted	Consumer	kVA	Half-hour demand	$/kVA

In theory the most efficient price signals would be fully dynamic – i.e. dynamic prices and dynamic Congestion Periods, which signal network congestion if and when it occurs (and avoids restraining demand when there is no congestion). The potential gain in efficiency over less dynamic options needs to be weighed against the cost of implementing a system that providers Retailers or Consumers with notice of impending Congestion to enable them to respond, and the level of complexity in implementing dynamic prices. If both prices and Congestion periods are notified at short notice, Consumers are faced with a high degree of uncertainty.

Currently, only dynamic Congestion Period signalling will be practicable in most cases, with posted (rather than dynamic) prices used. Where ripple control systems exist, it is already cost effective to provide dynamic Congestion Period signalling and various options exist for measuring Congestion Period demand, from the use of existing half hour metered demand to installation of separate two-register meters switched by the Congestion Period signal. The incentive to reduce demand will still occurs at the appropriate times of Congestion. The posted price should be set to signal the cost of upgrading the network to relieve Congestion.

Since the LRAIC is a long-term forward-looking cost, loss of efficiency in using posted, rather than dynamic, prices should be small. Therefore a reasonable cost-effective alternative is to use posted prices and dynamic Congestion Periods. Dynamic signalling of Congestion Periods is essential for limiting actual Congestion Period hours to, say, 1% of delivery hours.

15 There may be other variable price components if, for example, there is a limit to the amount that can be recovered by fixed charges

It is recommended that:

Congestion in networks should be signalled through posted prices applying during dynamic Congestion Periods where and when it is cost effective to do so – i.e. where and when the benefits of more precise price signals outweigh the costs of implementation including the metering and any equipment needed for dynamically notifying Retailers[16] or Consumers of when Congestion occurs.

Due to the unpredictability of weather variations it is extremely difficult to accurately predict Congestion Periods, though information can be provided based on previous patterns of Congestion Periods. Consumers want information about the predictability of the Congestion Period signal so that they can respond accordingly, otherwise they may simply not respond at all.

Where it is not cost-effective to dynamically signal Congestion Periods, or simply not effective to dynamically signal Congestion, posted periods (e.g. 7–11am and 5–9pm Monday to Friday) may be defined. Compared to dynamic signalling of Congestion, there is a loss in efficiency in that actual congestion might not occur during the pre-defined periods (and demand is unnecessarily reduced) or that congestion might occur outside those periods (and demand is not reduced and the Congestion results in load shedding). If the times of peak demand are reasonably predictable, the loss in efficiency should be small and, with a conservative definition of Congestion Periods, likely to be confined to a small amount of unnecessary load reduction.

Pre-defined bands approximating Congestion Periods can lead, not to a reduction in peak demand, but to a shifting of peak demand to times just outside the pre-defined bands. Defining shoulder periods adjacent to the pre-defined bands approximating Congestion Periods and setting shoulder period prices that are less than the peak prices will reduce such peak load-shifting.

If bands approximating Congestion Periods are pre-defined, the adoption of common definitions of Congestion Periods across Distributors would address the concern raised by Retailers that the current range of definitions is unnecessary and makes retail competition more difficult.

It is recommended that:

Where it is not cost-effective or ineffective to dynamically signal Congestion Periods:

- ***high price periods approximating Congestion Periods should be pre-defined:***

16 In the Wholesale Delivery Model, the Distributor signals Congestion to the Retailers and Consumers will respond to the prices set by Retailers

  - ***for winter-peaking networks, standard high price periods of 7am to 11am and 5pm to 9pm on week-days are recommended;***
  - ***a Distributor may define different high price periods and provide the reasons for varying from the above standard bands;***
  - ***for summer-peaking networks, the Distributor should publish the high price periods it uses to approximate Congestion Periods;***
  - ***the high price period should be restricted to the season in which the Congestion Period occurs;***
- ***in addition to the above high price periods, Distributors should define shoulder periods either side of each high price period where Congestion is possible;***
- ***the remaining periods are low price periods when Distributors do not expect Congestion to occur;***
- ***notwithstanding the pre-definition of high price and shoulder price periods, Distributors should also advise Consumers of periods when they do not expect Congestion to occur, and may offer Consumers guarantees that they will not face high, Congestion-related prices.***

5.2.1 Model price structure

The general form of prices will have fixed and variable price components. However, price components may differ depending on the information available to set different price components. Additional information that may be available and applicable is:

- the distribution network connected to a GXP may be further divided into geographical zones that have groups of ICPs within them;
- the connection or contract capacity at an ICP can be used to set a price component;
- the Connection Categories may be further divided into Load Groups to reflect different load characteristics.

The division of a Connection Category into Load Groups to reflect different load characteristics is only carried out where half-hourly metered data is unavailable.

Therefore, for Large Major and Major connections, the Connection Categories are identical to the Load Groups. Since the variable price component is aimed at influencing marginal demand, the price may have a larger fixed component. The additional fixed component can recover some of the Load-Dependent Costs by charging for connection or contract capacity. The variable component, charged on marginal demand, would be set to signal LRAIC. The same price structure should apply to General connections with half-hourly metering.

It is recommended that:

The model price structure for Large Major, Major and General connections with half-hourly metering should include:

- ***a fixed price component that recovers Consumer-Specific Costs and Load-Independent Costs; and***
- ***a fixed capacity price component based on contract or agreed capacity (in kVA) or the preceding year's peak demands (in kVA); and***
- ***variable Congestion Period price component charged on marginal demand (i.e. demand in excess of the capacity to which the fixed capacity price component relates) that reflects LRAIC, using any of the options set out in Table 4.***

This price structure and the costs to which the price components relate are shown in Table 4.

Table 4: Model Price Structure – Large Major, Major and General connections with half-hourly metering

Type of price	Price component	Costs to which the price is related
Fixed price	Equipment charge ($/yr)	Consumer-Specific Costs
	Connection ($/yr)	Load-Independent Costs
	Fixed capacity ($/yr = $/kVA/yr x kVA) using contract capacity, assessed capacity, capacity agreed with the Consumer or capacity based on the Consumer's preceding year's peak kVA demands	Load-Dependent Costs, reflecting LRAIC for the asset group and the geographical area in which the ICP is located
Variable demand price	$/kVA applying to demand in dynamic Congestion Periods	
	High/shoulder/low $/kVA applying to demand in posted Congestion Periods	

For consistency between pricing for connections with half-hourly metering (Major and Large Major, and some General connections) and those without half-hourly metering (most General connections), the pricing structures for General connections without half-hourly metering should be developed around the same price structure.

In the Wholesale Delivery Model, the General connections for each Retailer can be considered as a single connection with half-hourly metering. The Wholesale Delivery Model uses the reconciled quantities of energy assigned to each Retailer in each half hour at each GXP to determine each Retailer's purchases for their customers.

In the Retail Delivery Model, each meter type or function (GXP or ICP meters) is profiled into an average half hour profile. The form of the variable price component based on ICP meters will be limited by the economics of metering and the present base of retail tariffs and installed meter types. With the advancement of metering technology and economies of scale these limitations are likely to reduce in the future. Therefore the price structure for General connections in the Retail Delivery Model should provide for half-hourly and multi-rate metering options while recognising that currently most meters measure only energy consumption. Therefore the methodology for General connections in the Retail Delivery Model without half-hourly metering should not only align with the above methodology for connections with half-hourly metering but also be applicable where there are meters capable of recording more than just the accumulated energy consumption. Meters that record electricity consumption and/or the maximum demand over specified time periods[17] could be used so, potentially, Congestion Period and time-of-day pricing could be based on the maximum demands within those periods or the average demands (calculated from the energy consumption) over those periods. Multi-rate meters and half-hourly meters are just two of the options that could be considered for future ICP metering implementation when they become cost effective.

The types of meters currently used for General connections without half hourly-metering are generally energy meters measuring accumulated electricity consumption but some Consumers also have meters that measure energy which is subject to restrictions on use – e.g. night-time use only. For General connections without half-hourly metering, the ICP metered data that is generally available is:

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

General connections without half-hourly or multi-rate metering cannot be charged demand prices; therefore, for pricing purposes, other relevant considerations are taken into account. These include whether a Consumer's load is controllable, the conditions relating to the use of control and whether supply is restricted to times outside the Congestion Periods (e.g. night-time) periods.

[17] For the purposes of this recommendation these meters will be referred to as multi-rate meters, which mean meters with registers capable of recording consumption in a minimum of three separate time periods.

Price signals that can be sent to Consumers to encourage demand moderation during Congestion Periods include:

- higher prices for consumption in Congestion Periods relative to other times. To signal the potentially higher costs imposed by uncontrollable consumption during Congestion Periods, there should be two distinct prices:
    - one for delivery during the Congestion Period(s), which may be signalled dynamically or posted; and
    - another for delivery at all other times.
- lower prices for consumption during non-Congestion Periods or compensating Consumers for controllable load.

The recommended Retail Delivery Model price structure for General connections without half-hourly or multi-rate metering is shown in Table 5.

Table 5: Variable Retail Delivery Model prices – General connections without half-hourly or multi-rate metering

Description	Signal to consume or not consume		Consumption elected by	Quantities	Measured as	Price
	Price	Time				
24 hours Supply	Posted	Posted	Consumer	kVA or kWh	Aggregate (kWh) over whole time period	$/kVA or c/kWh
Day supply	Posted	Posted	Consumer	kVA or kWh	Average (kVA) or aggregate (kWh) over defined period	$/kVA or c/kWh
Night supply	Posted	Posted	Consumer	kVA or kWh	Average (kVA) or aggregate (kWh) over defined period	$/kVA or c/kWh
Controlled Supply	Posted	Dynamic	Supplier	KWh	Aggregate over non-controlled period	c/kWh

It is recommended that:

Retail prices for General connections without half-hourly or multi-rate metering include:

- ***a fixed price component that recovers Consumer-Specific Costs, Load-Independent Costs and, if appropriate, the capacity part of the Load-Dependent Costs.***
- ***a variable average demand or consumption component using high, shoulder and low prices. These prices can be used to calculate equivalent prices in the***

Retail Delivery Model for Consumer supply options that provide continuous, controlled or restricted delivery.

The fixed capacity price component might not be able to be applied to all Consumers – e.g. domestic Consumers, to whom a low fixed charge tariff option must be offered. It may be appropriate, and even essential, to apply to some Consumers whose consumption is such that they would be uneconomic to supply without fixed charges – e.g. holiday homes, irrigation.

Recognising the base of existing metering and present technical and economic limitations, it is necessary to convert these prices to aggregate options by the application of typical load profiles. Aggregate options that use existing metering and load control systems and provide price stability while enabling Consumers to move to more time-of-use-related prices when there is a net benefit of doing so, are shown in Table 6.

Table 6: Retail Delivery Model Price Structure – General connections without half-hourly metering

		Domestic (up to 15kVA)	Non-domestic (up to 15kVA)	Medium (16-70kVA)	Large (71 kVA+)
Fixed Prices					
- Connection and/or Capacity Charge ($/day or $/kVA/day)					
- Transformer ($ per day)					
Variable Prices					
Options					
- 24 hours Supply					
A	- High (c/kWh)				
	- Shoulder (c/kWh)				
	- Low (c/kWh)				
B	- Anytime (c/kWh)				
C	- All Inclusive (c/kWh)				
D	- Day (c/kWh)				
	- Night (c/kWh)				
- Controlled Supply					
E	- Controlled (c/kWh)				
	- Night Only (c/kWh)				

- Night plus Boost (c/kWh)						
Unmetered Supply						
	Street Lights	**Other**				
Fixed Price						
- Connection Charge ($ per day)						
Variable Prices(c/kWh)						
- 24 Hour (assessed)						

In Table 6, the price options for connections without half-hourly metering are the preferred time-of-use option based directly on the high, shoulder and low prices (option A) plus approximations to it (options B, C, D and E) that follow existing practice. The prices for the variable components of these latter options need to be derived using the load profiles for each Load Group and price option. The variable components of these options[18] are:

- anytime – 24 hour uncontrolled supply;
- day/night – 24 hour supply with day and night supply measured separately. The hours of day usage are defined as being between [7am] and [11pm];
- controlled - supplies that may be for less than 24 hours but with minimum availabilities of say [20] or [16] hours per day;
- night only – supply between [11pm] and [7am] only;
- night plus boost - supply between [11pm] and [7am] and between [1pm] and [4pm] only.

There is also an all inclusive option, where part of the supply able to be controlled, but with both controlled and uncontrolled supply through a single meter. This is a combination of anytime and controlled supply that uses assumed proportions of anytime and controlled supply. In the example calculation in Annex 3, the assumed proportions are 60% anytime and 40% controlled. The setting of prices for day, anytime and night supply should take into account the season (summer or winter) in which the Congestion periods occur.

The aggregate of the load profiles of Consumers on the various price options in a Load Group is the load profile for that Load Group. For example, for domestic Consumers in the up to 15kVA Load Group, the load profiles of the anytime, all inclusive, day/night, controlled, night-only and night plus boost add to that Load Group's profile.

The prices are determined by:

- breaking down the total load of the group into time periods – half-hourly and then into high, shoulder and low periods. Where the raw data is GXP data, and the day and

[18] The times and hours in [ ] are guidelines. The times may be varied by each distributor to better align with its Congestion periods

night loss factors differ, the difference is taken into account in calculating the corresponding ICP data.

- creating proportionate profiles for each meter type according to the proportion of each period (high, shoulder or low) that supply is available.
- calculating the proportionate usage in each period for the meter types that are mutually exclusive – day and night. These give the prices for day and night usage.
- calculating a residual profile for the remaining price options of night plus boost, controlled etc.
- calculating the proportionate usage in each period of the night plus boost and controlled type according to the proportion of each period (high, shoulder or low) that supply is available. These give the night plus boost and controlled prices.
- calculating the anytime load profile as the residual. This gives the proportionate anytime usage in each period, which is used to calculate the anytime price.
- assessing the relative proportion of anytime and controlled usage that makes up the all inclusive load - e.g. 60% anytime and 40% controlled – and calculating the all-inclusive price as a weighting of the anytime and controlled prices.

An example of these calculations is given in Annex 3 for a hypothetical case in which the load profile of a Load Group without half-hourly metering is 10% high, 20% shoulder and 70% low.

Some of the costs for General connections are fixed and should be reflected in fixed prices. However, for domestic Consumers, the Government has passed regulations requiring a low fixed price option so the fixed prices will not necessarily align with the fixed costs. Where the fixed price in Table 6 would exceed the limit imposed by legislation (for small domestic Consumers using < 8000kWh/year), a low fixed price option will need to be offered. This will require a uniform adjustment to the high, shoulder and low variable delivery prices and the variable prices – anytime, all-inclusive, etc. - derived from them.

Setting different variable delivery prices for anytime, time-of-use and controllable delivery to Consumers is possible only in the Retail Delivery Model. Under the Wholesale Delivery Model there is an incentive on Retailers to reduce peak demand (due to the high demand prices during the Congestion Periods) but a Retailer with a greater than average proportion of Consumers with controllable load does not obtain the full benefit (in terms of reduced demand charges) of that controllability. An alternative means of signalling the benefit of load control or night-only delivery under the Wholesale Delivery Model would be to compensate Retailers selling to Consumers with controllable or night-only usage by making a fixed payment equivalent to the estimated value to the Distributor of demand reduction. This would provide a means by which Distributors could provide Retailers an incentive to encourage restricted time-of-use – e.g. night-only - and controllable delivery.

5.3 Distributor Business Models

The Wholesale and Retail Delivery Models differ in the way in which the quantities for charging are measured. The Retail Delivery Model uses the metered or estimated quantities at ICPs to charge Retailers or Consumers; the Wholesale Delivery Model uses the reconciled GXP metered quantities to charge Retailers. A pure Wholesale Delivery Model would "measure" its services based solely on the quantities of electricity sold by each Retailer as determined under the Reconciliation Process and metered at the GXPs, while the Retail Delivery Model would "measure" its services according to Consumers' metered offtakes – i.e. at the ICPs.

In practice, the Wholesale Delivery Model does not rely solely on reconciled data at the GXPs. To reflect clearly distinguishable costs, Consumer-Specific Costs are separately priced and loads are categorised according to the assets groups that they use.

In the submissions received in response to the 3 August 2004 Discussion Paper, the relative merits of these two business models attracted the greatest number of responses. It is difficult to objectively compare the two models, because a feature of one model may be considered an advantage by one party and a disadvantage by another. In particular, the relative lack of detail in the Wholesale Delivery Model in prescribing Consumer prices was regarded by some submitters as creating opportunities for efficient innovation by Retailers, while others regarded it as providing Retailers with insufficient information to pass on distribution costs efficiently.

Therefore in this revised paper, the differences between the two models are listed. Since there is a reasonably well accepted theoretical basis for network pricing, the two models are compared first against the fundamental requirements of efficient prices.

Table 7: Business Model Comparison - Pricing Fundamentals

Pricing Fundamentals		
	Wholesale	**Retail**
Distribution prices should recover the economic costs of providing the distribution service	Recovers total economic costs, subject to price regulation (that in principle allows a Distributor to recover economic costs).	Recovers total economic costs, subject to price regulation (that in principle allows a Distributor to recover economic costs).
Distribution prices should approximate the theoretical benchmark of nodal pricing where nodal pricing is impractical	In a pure Wholesale Delivery Model, distribution prices would be calculated according to Retailers' ownership of electricity at the GXP. A single variable demand price at the GXP implies delivery to a single node – i.e. a notional point within the distribution network to which all Consumers/Retailers' customers are connected. In practice, Consumer-Specific Costs are separately recovered. They would normally be outside the theoretical nodal pricing benchmark anyway. In the Wholesale Delivery Model	The Retail Delivery Model allows for a closer approximation to the nodal pricing benchmark in distribution networks where there may be different costs in delivering to different groups of ICPs. If there is more than one zone supplied from a single GXP (for the reasons given in section 4.4.1), the Retail Delivery Model can distinguish between them. The nodal prices would differ between two zones if the network was congested between the zones and/or one zone was significantly further from the GXP than the other.

	price structure as practised, there are effectively three nodes, corresponding to the three Connection Categories, Large Major, Major and General.	
Prices should reflect cost differentials relating to density, configuration of area covered and customer type	In the Wholesale Delivery Model, an average density, configuration of area covered and customer type are assumed for each Connection Category with the maximum disaggregation at GXP level.	In the Retail Delivery Model, an average density, configuration of area covered and customer type are assumed for each Connection Category in each zone. It can, for example, distinguish between urban and rural zones, and on the basis of differential service quality. The Retail Delivery Model can also differentiate between customer types. By defining Load Groups for Consumers with similar load characteristics, it is able to set prices that may better reflect network cost drivers.
Efficient distribution prices will have fixed and variable price components. The fixed component should not influence use of the distribution services. The variable component should signal congestion costs.	The fixed component of the wholesale price recovers Consumer-Specific and Load-Independent Costs. There may also be a fixed component recovering part of the Load-Dependent Costs. The variable component recovers the LRAIC on Retailers' allocation of demand at the GXP during Congestion Periods.	The fixed component of the retail price recovers Consumer-Specific and Load-Independent Costs. There may also be a fixed component recovering part of the Load-Dependent Costs. There is also a variable component that recovers LRAIC on Consumers' marginal demand during Congestion Periods over the selected geographical zones.
Distribution pricing methodology should not prevent a Distributor entering into the most efficient contractual arrangement for its circumstances	Can be used only where there is an interposed contractual arrangement between the Distributor and Retailers.	Can be used by a Distributor with either interposed contracts with Retailers or conveyance contracts with Consumers

The Wholesale Delivery Model then has advantages of lower costs and simpler pricing structures for the Distributor than the Retail Delivery Model. Offset against this are weaker pricing signals to Retailers due primarily to the present limitations in the Reconciliation Process and the need for Retailers to repackage distribution pricing to enable the Consumers in the General connections category to see these pricing signals. However, the benefit of modifying the behaviour of those Consumers depends on the extent to which the network (or zone within it) is congested and the ability of those Consumers to respond to the price signals. The Retail Delivery Model also facilitates the targeting of prices to reflect higher levels of service quality to different Consumer groups. This latter issue should not be overlooked in the light of the Commerce Commission Threshold Regulation requiring a price/quality trade-off to be established requiring Consumer engagement.

In theory, neither the Wholesale nor the Retail Delivery Model can be considered as fundamentally more or less efficient than the other under all circumstances. For example, where load is uniformly spread across those parts of a distribution network connected to a GXP and the configuration of the network is such that any congestion will affect all loads, the Wholesale Delivery Model can be more efficient (because it is simpler). However, where this is not the case and the part of the network connected to a single GXP needs to be divided into zones to reflect significantly different network characteristics, the Retail Delivery Model is more efficient.

In the long term, the Retail Delivery Model has the potential to be better suited to tailoring prices to smaller Consumers' quality needs. The Wholesale Delivery Model, and the GXP data on which it relies, do not distinguish units taken by non-half-hour metered Consumers with quality needs that may differ from those of other Consumers. Although the Commerce Commission regulatory regime has yet to fully develop price-quality trade-offs, these may be developed in the near future and be applied when the price and quality thresholds are reset.

6. Conclusions

6.1 Meeting the Guiding Principles

The recommendations in this paper are aimed at meeting the objectives of the Guiding Principles and in particular to:

- provide efficient price signals for utilisation of and investment in the network,
- relate to the level of service and reflect the cost structures and risks and be easily understood; and
- encourage technology innovation.

The recommendations do not prescribe a single price methodology; but provide a framework of options that meets these objectives by:

- setting out how a Distributor should allocate its costs and target its revenue recovery from different parts of the network and from different categories of loads, including by differentiating according to service quality. Thus the prices will reflect the level of service and cost structures by:
- providing a high degree of transparency of how the costs are categorised and the shared network costs are allocated to Network Asset Groups according to ORC and then to Load Groups according the key cost drivers of Anytime Maximum Demands and Coincident Peak Demands. This provides a relatively simple method of cost allocation that is easily understood.
- developing price structures that allow for risk-sharing between a Distributor and its Consumers in terms of:
  - for Major and Large Major connections, choosing between fixed capacity prices and variable demand and excess demand prices;
  - Distributors choosing to offer Wholesale Delivery Model pricing to Retailers or Retail Delivery Model pricing according to end use loads. The different costs and risks of these two Distributor business models are identified in this paper.
- promoting efficient use of and investment in the network through variable demand charges for Major and Large Major connections and higher Congestion Period prices for General connections that enable Distributors to signal where and when demand should be reduced. The recommendations do not prescribe price levels for Congestion and other prices but allows Distributors to determine differences in those prices according to their need to limit peak demands.

- encouraging technology innovation by:
  - providing for dynamic forms of price signalling during times of network congestion;
  - encouraging metering improvements to improve price signalling to loads. The installation of enhanced metering is encouraged by offering time-of-use prices. Consumers whose loads impose less demand on the network than the Load Group average can benefit from installing time-of-use metering.

Table 8: Business Model Comparison – Guiding Principles

Test against Guiding Principles		
Guiding Principle	**Wholesale Delivery**	**Retail Delivery**
Prices should encourage efficient investment and technology innovation in the provision of distribution services		The structure of the Distributor's pricing should not have a significant influence over how a Retailer structures its prices. Otherwise, Retailers become very limited in how they can compete and innovation by the Retailer is stifled (Orion)
	The Wholesale Delivery Model provides a more open platform for Consumers and Retailers to adopt more innovative technologies to respond during Congestion Periods, as there is more freedom for the customer (Retailer) to respond to pricing through technology choices (CRA)	
		The Retail Delivery Model better aligns with a Distributor's core function of delivery from a GXP to an ICP, including the risk of losses (technical and non-technical). (Trustpower)
Prices should not create inefficient barriers to entry in the market for distribution services		Under an interposed contractual arrangement a retail price structure is less appropriate primarily because it dictates to the Retailer the form of metering and consumer pricing used by Retailers, thus inhibiting competition (Orion)
Prices should not unjustifiably discriminate between Retailers/Consumers of the Distributor	Discriminates against the incumbent Retailer due to use of energy reconciliation data (Contact)	No discrimination (Contact)
	In the Wholesale Delivery Model, Retailers are allocated a proportion of the residual profile only if they do not submit data on deemed profiles (Powerco)	
Prices should encourage the efficient use of distribution services	GXP-quantity pricing removes both information and incentive for Retailers to pass relevant signals to specific consumers (Aurora)	It cannot be demonstrated that the higher administrative costs of ICP-quantity pricing are compensated by better Retailer or Consumer motivation and thus better asset usage (Aurora)
		No difference unless controlled load is separately metered under the

		Retail Delivery Model . (John Noble)
		The Retail Delivery Model does not dilute the pricing signals created by the pricing methodology (Trustpower)
	Wholesale pricing does not dilute pricing signals any more than retail pricing. In both cases, Retailers rebundle the line charges (Powerco)	
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	Can only be done at GXP level (Contact)	Can be done at a finer level of disaggregation (Contact)
	GXP-quantity pricing removes information such as load profile (which Distributors inherently apply when assigning an ICP to a load group), zone characteristics below GXP (local cost structure, congestion, unconstrained, atypical losses, bypass threat) (Aurora)	
		The Retail Delivery Model has the flexibility to be able to provide appropriate pricing signals on different networks (and within those networks) irrespective of the differing demand and loading characteristics of those networks (Trustpower)
		ICP-based pricing links service levels more effectively (Vector)
Changes to pricing methodology (and the rationale for them) should follow consultation with interested parties, and be widely publicised, transparent, predictable and readily verifiable	Wholesale Delivery Model fails against the criteria of transparency (and ease of administration). Transparency is also a requirement of the GPS (formerly para 12, now para 13) (Mighty River Power)	
Prices should satisfy legal and regulatory requirements		

Glossary of Terms

This glossary explains the meanings of certain terms as used in this paper.

Anytime Maximum Demand (AD) - means a Load Group's after diversity Anytime Maximum Demand calculated or assessed in accordance with the recommendation set out in section 4.5.1

Coincident Peak Demand (CPD) - means a Load Group's Coincident Peak Demand calculated or assessed in accordance with the recommendation set out in section 4.5.1

Congestion – refers to when a distribution network or part thereof is or is expected to be congested - i.e. at or close to its maximum loading capacity.

Congestion Period – means any period defined in advance or signalled in real time when Congestion occurs and network usage is priced differently from usage at other times or when specific load control strategies are implemented by the Distributor.

Connection Category – means a Load Group that is defined according to its use of network assets as set out in 4.5.2

Consumer – has the same meaning as in the Electricity Act 1992

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

Distributor – means an electricity lines business as defined in the Electricity Industry Reform Act 1988 other than Transpower

General – refers to the Connection Category or Load Group(s) that are supplied from the LV network (and so are deemed to use the LV and all higher voltage distribution assets)

Large Major - refers to the Connection Category or Load Group(s) that are supplied from the sub-transmission network (and so are 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-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

Load Group – means a category of Consumers from which Load-Dependent Costs will be recovered

Major - refers to the Connection Category or Load Group(s) that are supplied from the 11kV network (and so are deemed to use the 11kV and all higher voltage distribution assets)

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.

Reconciliation Manager – has the same meaning as in the Electricity Governance Rules 2003

Reconciliation Process – means the process set out in Part G Section VI of the Electricity Governance Rules 2003 by which the Reconciliation Manager calculates the amounts of electricity purchased through each Grid Exit Point (GXP) by purchasers

Retail Delivery Model - means an electricity distribution business model in which the Installation Control Point (ICP) metered quantities are used by the Distributor for charging the Retailers or Consumers.

Retailer - means an "electricity supply business" as defined in the Electricity Industry Reform Act 1988.

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

Wholesale Delivery Model - means an electricity distribution business model in which reconciled GXP metered quantities are used by the Distributor for charging the Retailers.

Annex 1 – Retailers' and Consumers' Concerns

The contents of this Annex 1 were provided by the Retailer and Consumer representatives on PAWG to provide their perspectives on distribution pricing.

Retailers' concerns

Complexity on a national basis

- While each network may consider that its individual distribution pricing structure is not unduly complex, the combination of all the pricing structures results in an excessively complex distribution pricing system nationally. Increased consistency in final price structure is important to Retailers for administration efficiencies.
- Appropriate granularity of pricing - Some Distributor's pricing structures are excessively complex to apply. Distributors need to strike an appropriate balance between a desire for economic 'purity' in their pricing and excessive complexity, given the administrative burden it creates for Retailers.

Inconsistency of definitions

- Currently Distributors use the same word with varying definitions. For example 'domestic' has a different meaning on nearly every network. This makes it nearly impossible for a Retailer to provide accurate advice to a Consumer on the conditions that need to be met to be eligible for this definition. Consistency in Consumer grouping also needs to include consistency in definition of the group. There are many examples of this type of problem e.g. day, night, peak, night only, night with boost, capacity limit (e.g. whether it is 15kVA or some other value).

Use of RM reconciled data

- Use of Reconciliation Manager (RM) data creates an inequality between the incumbent Retailer and other Retailers. The calculation of volumes for the incumbent Retailer is on a different basis to that of other Retailers, which is contrary to the MDAP guiding principle: "prices should not unjustifiably discriminate between Retailers/Consumers of the Distributor". Some Retailers strongly believe that the Wholesale Delivery model may discriminate against incumbent Retailers.

Pricing not applicable to the metering at Consumers' installations

- Pricing structures that are based on the peak demands at GXPs cannot be reconciled to individual Consumer's installations at the mass market level because it is (currently) not economic to install half hour metering at this level. Charges from Distributors cannot be attributed even in a coarse way to categories of Consumers (let alone individual Consumers). Nor are Retailers able to satisfactorily reconcile charges from Distributors with their own recovery from Consumers.

- Charging that is determined retrospectively. For example, the retrospective application of peak demands to pricing shifts a business risk to the Retailer that should more properly belong to the Distributor.
- Administrative burden. Charging that depends for final determination on the wash-up cycle accompanying the NRM process creates uncertainty and an administrative burden for Retailers.

Weak price signals for efficient use of networks under wholesale delivery pricing

- Load control is a key method of avoiding unnecessary investment in a network. With retail delivery (ICP) pricing the network can send strong price signals to encourage load control. Under wholesale delivery (GXP) pricing there is a much lower incentive for Retailers to provide these signals to Consumers as the peak charge is allocated based on kWh rather than actual kW. Therefore Retailers pay the same peak charge regardless of their mix of controlled and uncontrolled load so the incentive to show a differential in retail prices is weak. The objective to “provide efficient price signals for utilisation of and investment in the network” is better served by retail rather than wholesale pricing.

- Because peak charges cannot be accurately allocated directly to Retailers the decisions of one Retailer’s Consumers affect the charges to all other Retailers. For example, Retailer 1 may not differentiate between controlled and uncontrolled load so the Consumer has the ripple relay removed. This will lead to a higher peak, meaning increased charges for all Retailers. For example, if Retailer 1 has 5% of the volume under the residual profile it will pay just 5% of the increase in peak charge caused by its Consumer’s decision. The incumbent will pay most of the extra cost even though it was not caused by it or its Consumers. Therefore Retailer 1 has little incentive to signal the need for load control to its Consumers, which could lead to the need for inefficient investment in the network and puts most of the extra costs on the incumbent Retailer. In contrast if Retailer 1 was charged 4c/kWh for controlled load and 6c/kWh for uncontrolled load it would have a strong incentive to pass this cost differential through to Consumers who would then see the benefit of load control. If a Consumer then chose to remove their ripple relay they would pay substantially more and this would have no effect on the charges of other Retailers.

Retrospective adjustments

- Some charges are currently calculated on demands from previous time periods, requiring payments that are difficult to predict and, if there has been a change of

Retailer, relating to demands when the Consumer was supplied by another Retailer. The problem is not that the charges relate to a previous period (provided they are known by Retailers in advance) but that there are retrospective adjustments (or wash-ups) of the charges.

Lack of transparency – wholesale delivery pricing

- It is expected that Retailers will be required to disclose line charges in Consumer prices (and this requirement is part of the draft model Consumer contract being developed). With wholesale delivery pricing, the calculation of Consumer line charges is left to Retailers who, without sufficient information from the Distributor on how Consumer line charges were allocated them, will disclose different line prices depending on their own assumptions as to how the line charges were allocated.

Consumers' concerns

Consumers' concerns are largely focussed on the amount Consumers pay for distribution services. Some, particularly large, Consumers are concerned about the way in which their prices have been determined but are limited in their ability to analyse the prices because of the complexity of the price methodology and/or the lack of transparency of the price methodology. This is exacerbated by vague and imprecise information disclosure regulations and the lack of a forum in which disputes can be arbitrated.

Line charges not shown by Retailers

- Retailers' invoices to small and medium Consumers do not separately show the line charges so Consumers have little information on the prices they pay for distribution services. This could be addressed by Distributors billing Consumers directly for distribution services (or billing on behalf of Retailers for energy as well). In any case the prices as such are not so important; the key issue is to demonstrate to Consumers that they are not being overcharged and the best way of doing this is to have an independent agency verify that any price increase is justified.

Inadequate information disclosure

- In order for a Consumer to understand its prices, it must understand how its Consumer (or load) group was allocated a part of the total distribution cost, and how those costs were translated into prices. The information disclosure regulations help to some extent but the disclosed information is insufficient and much of it is not directly relevant to the calculating prices. As noted above, there should be an independent agency to verify that any price increase is justified.

Inappropriate cost allocation

- Some Distributors set their prices to specific Consumers by reference to the by-pass cost which, given the overall limit to a Distributor's revenue, indicates an inappropriate allocation of costs.

No or weak signals for load control

- There is a mixture of incentives for load control. Retailers control load to manage wholesale electricity prices and Distributors to manage network Congestion. If distribution prices do not signal the need for load control or the distribution prices are bundled into the retail price, most of the incentive for Consumers to reduce load to manage network Congestion is lost. The benefit of signalling the need for load control to Retailers is very small, because the difference between on and off peak energy prices, and allowing for the time that control can reasonably be imposed, gives a relatively small reward compared with the value of avoided network reinforcement. Most Retailers make a difference between "anytime" and "controlled" supplies, which usually shows up as a difference in the energy price, and which presumably reflects the difference in the applicable line tariff.

No dispute resolution process

- Consumers that consider distribution prices to be excessive have no body to take their dispute to.

Government intervention in distribution pricing

- The low fixed charge tariff regulations add complication and distortion to distribution (and retail electricity) pricing.

Addressing Retailers' and Consumers' Concerns

Most of the above Retailers' and Consumers' concerns are addressed by the model framework and methodologies, but some are outside the scope of the price methodologies themselves.

The Retailers' and Consumers' concerns that are addressed by the recommended framework and methodologies are:

Complexity on a national basis - In recommending more standardised approaches to cost allocations, definition of Load Groups and price structures, there should be less complexity on a national basis for Retailers selling delivered electricity in several networks. However the goal of reducing complexity of pricing should not override the efficiency objective. The aim is to reduce unnecessary complexity – e.g. where there are minor differences in the definitions of time periods, such as day/night and high/shoulder/low periods, and where different asset group or Load Group categorisations are not warranted by material cost differences.

Retrospective adjustments – The proposed methodologies allow for prices calculated on the basis of preceding year's demands. These can (and should) be advised in advance of the current year's prices and avoid the need for any retrospective adjustments.

Inappropriate cost allocation – The recommended cost allocations will address the issue of some Consumers being allocated costs on the basis of the Consumer's alternative cost of by-pass.

Mixture of incentives for load control – The recommended approach to signalling the need for Consumers to control load addresses this issue. However, the Retail Delivery Model is more effective in achieving this, as Retailers facing wholesale delivery prices presently have relatively weaker incentives to encourage Consumers to control load.

The Retailers' and Consumers' concerns that are not directly related to pricing methodology or not specifically addressed by the recommendations are:

Wholesale Delivery Model pricing (use of Reconciliation Process data, pricing not applicable to metering at Consumers' installations, weak price signals for efficient use of networks, lack of transparency) – The concern is that, under current Reconciliation Process arrangements, the Wholesale Delivery Model could be perceived as discriminating against the incumbent Retailer. Another concern is that pricing signals to Retailers are weaker than in the Retail Delivery Model and Retailers are required to repackage distribution pricing for most General connections Consumers. However, as noted in section 5.3, this is due primarily to the shortcomings in the existing Reconciliation Process and PAWG notes that further work is being carried out by an industry working group on developing the Reconciliation Process.

Lack of transparency (line charges not shown by Retailers, inadequate information disclosure) – While the Retail Delivery Model provides Retailers with the opportunity to provide transparent distribution prices to mass-market Consumers, under the Wholesale Delivery Model a conversion process is required. This conversion is already undertaken by the Ministry of Economic Development in its Domestic Electricity Price monitoring and so is not insurmountable. The information disclosure regime should provide Consumers with the information relevant to verifying that their prices have been calculated according to the disclosed price methodology. This issue is not strictly a pricing methodology issue but relates to how pricing is communicated to Consumers.

No dispute resolution process – This is outside the immediate scope of developing model approaches to distribution pricing. However, a more transparent approach, as is recommended, should provide Consumers with information on whether or not their prices have been appropriately determined.

Government intervention – The recommendations in this paper have acknowledged the need to conform to the low fixed charge option that the Government requires to be offered to low-usage domestic Consumers. This adds complication to pricing as well as distorting the price signals.

Table 9: Summary of Views – Stakeholder Concerns

Meeting Stakeholders' Concerns		
	Submissions	**Wholesale vs. Retail Delivery**
Complexity on a national basis	Recommendations too broad to effectively address this (Contact) A single model approach should be used – (Genesis) Model approaches should be developed for both wholesale and retail delivery (Meridian) A single model approach should be used (Mighty River Power) A single model approach should be used (Trustpower)	Preference for Retail Delivery Model (Genesis) Strongly support Retail Delivery Model (Mighty River Power) Strongly in favour of Retail Delivery Model (Trustpower)
Inconsistency of definitions	Not addressed (Contact) Not addressed - additions and alterations suggested (Aurora)	
Use of RM reconciled data	Recognises this is a problem with wholesale pricing (Contact) No evidence to indicate that GXP pricing puts incumbent retailer at any material risk (Aurora) National electricity reconciliation system not designed for distributor line pricing (Trustpower)	Retail superior (Contact)
Pricing not applicable to the metering at Consumers' installations	Not addressed (Contact)	Retail superior (Contact)
Weak price signals for efficient use of networks under wholesale delivery pricing	Acknowledged (Contact) GXP-quantity pricing removes both information and incentive for Retailers to pass relevant signals to specific consumers (Aurora)	Retail superior (Contact) Wholesale pricing does not dilute pricing signals any more than retail pricing (Powerco)
Retrospective adjustments	Hardly mentioned (Contact)	Retail generally superior as wash-ups are associated with wholesale pricing (Contact)
Lack of transparency – wholesale delivery pricing	Not addressed (Contact) The price signals a distributor wishes to send may be contradicted by the price signals a retailer wants to deliver. Retailers should undertake to pass distribution price signals through (Vector).	Retail superior (Contact) Wholesale pricing requires retailers to make various assumptions as to the cost of line services to any particular ICP (Trustpower)

Line charges not shown by Retailers	Not a distribution pricing methodology issue (Aurora)	GXP-quantity pricing and transmission charges not transparently divisible to ICP quantities for retailer billing to consumers (Aurora)
Inadequate information disclosure	Not a distribution pricing methodology issue (Aurora)	
Inappropriate cost allocation		
No or weak signals for load control	Not considered a problem (Aurora)	
No dispute resolution process	Not a distribution pricing methodology issue (Aurora)	
Government intervention in distribution pricing		

Annex 2 – Application of Cost Allocation Methodology

To allocate costs to the Load Groups categorised in section 3.5.3 (which exclude special load categories such as street lighting, irrigation etc.), an assessment of the relative weighting of AMD and CPD is needed in order to allocate costs. The most appropriate weighting to use depends on the network/load configuration. Assessments by Distributors based on actual networks indicate that the weighting of AMD and CPD for allocating total network costs will be close to 50:50, with a probable range either way of 40:60. For Load Groups other than the special load categories PAWG recommends that a 50:50 weighting should be applied to weighting Load Groups' AMD and CPD to allocate costs. However, it is recognised that other weightings may be appropriate for some networks and where a Distributor applies a different weighting the weighting and reasons for it should be disclosed.

The disaggregation of network assets to asset groups, the allocation of direct costs to those asset groups and the allocation of asset group costs to Load Groups forms the basis for calculating the target revenue to be recovered from each Load Group.

The following Table A1 illustrates this cost allocation process. The inputs to the allocation process for a single zone or geographical area are:

- the costs associated with each asset group (denoted in the table by, for example, T_{11} for the 11kV asset group in the area);
- the AMD and CPD of each Load Group (denoted by AD_{L_2} for Load Group L_2, for example); and
- the weighting factors w_{AMD} and w_{CPD} (proposed in section 3.5.3 to be equal at 50% each).

First the AMD and CPD of the Load Groups are normalised to calculate each Load Group's proportion of total AMD and CPD. The normalised anytime and coincident demands, denoted by ad_{L_i} and cd_{L_i} respectively, are then weighted using the weightings w_{AMD} and w_{CPD} to calculate allocation factors W_{L_i} are allocation factors for each Load Group.

The asset group costs, denoted by T_{LV}, T_{SS}, etc, are allocated according to each Load Group by the W_{L_i} allocation factors. For example, if two Load Groups, L_1 and L_2, are using the LV network, the total LV network cost T_{LV} is shared between them as $T_{LV} \times \frac{W_{L_1}}{W_{L_1} + W_{L_2}}$ and $T_{LV} \times \frac{W_{L_2}}{W_{L_1} + W_{L_2}}$.

This allocation of asset group costs is carried out for all asset groups from the LV network through to the subtransmission network so that each Load Group is allocated a part of the cost of each asset group that is used to supply it.

The total cost allocated to each Load Group is the sum of all the asset costs allocated to it. For example, the total cost T_{L1} allocated to Load Group L_1 is the sum of $T_{LV} \times \frac{W_{L1}}{W_{L1} + W_{L2}}$, …., through to $T_{ST} \times \frac{W_{LN}}{W_{L1} + ... + W_{LN}}$.

For the special category Load Groups such as streetlighting, irrigation etc to which the weightings w_{AMD} and w_{CPD} do not apply, the relevant demands can be calculated directly and used to allocate shares of network costs.

Where a Load Group L_i is further disaggregated by service level, the allocated costs T_{Li} are for the combined Load Group. There is no distinction between the costs allocated to the urban and rural Load Groups within that Load Group. Rather, both rural and urban loads will be allocated the same average cost, but will have different Consumer service level commitments.

Table A1: Allocation of asset group costs to Load Groups

	Allocations of costs to Load Groups				
	L_1	**L_2**	**………**	**L_N**	
Anytime demands	AD_{L1}	AD_{L2}		AD_{LN}	$\sum_{i=1}^{N} AD_{Li}$
Normalised anytime demands	$ad_{L1} = \frac{AD_{L1}}{AD_{L1} + AD_{L2} + ... + AD_{LN}}$	ad_{L2}		ad_{LN}	100%
Coincident demands	CD_{L1}	CD_{L2}		CD_{LN}	$\sum_{i=1}^{N} CD_{Li}$
Normalised coincident demands	$cd_{L1} = \frac{CD_{L1}}{CD_{L1} + CD_{L2} + ... + CD_{LN}}$	cd_{L2}		cd_{LN}	100%
Weighted Average	$W_{L1} = w_{AD} \times ad_{L1} + w_{CD} \times cd_{L1}$	W_{L2}		W_{LN}	100%

Asset Groups	**Allocations of costs**				
LV cables, lines & plant;	$T_{LV} \times \frac{W_{L1}}{W_{L1} + W_{L2}}$	$T_{LV} \times \frac{W_{L2}}{W_{L1} + W_{L2}}$	……		T_{LV}
Shared distribution substations;	**X**	**X**			T_{SS}
11kV cables, lines & plant;	**X**	**X**	**X**		T_{11}
Zone substations;	**X**	**X**	**X**		T_{ZS}
Subtransmission, HV network;	$T_{ST} \times \frac{W_{L1}}{W_{L1} + ... + W_{LN}}$	**X**	**X**	$T_{ST} \times \frac{W_{LN}}{W_{L1} + ... + W_{LN}}$	T_{ST}
Dedicated equipment			**X**	**X**	
Totals	T_{L1}	T_{L2}		T_{LN}	$\sum_{i=1}^{N} T_{Li}$

Annex 3 – Price Calculation Example

An assumed profile of 10:20:70 high:shoulder:low is used in this hypothetical example to calculate prices for the price options:

- anytime – 24 hour uncontrolled supply;
- all inclusive – 24 hour supply with part of the supply able to be controlled, but with both controlled and uncontrolled supply through a single meter;
- day/night – 24 hour supply with day and night supply measured separately. The hours of day usage are defined as being between [7am] and [11pm].
- controlled - supply that may be for less than 24 hours but with a minimum availability of [20] hours;
- night only – supply between [11pm] and [7am] only; and
- night plus boost - supply between [11pm] and [7am] and between [1pm] and [4pm] only,

assuming prices of:

- $100/MWh high
- $75/MWh shoulder
- $15/MWh low.

The input assumptions (or required input data) are highlighted in yellow. It is also assumed that all inclusive usage is made up of 60% anytime and 40% controlled.

The calculated prices are:

- Night-only $15/MWh
- Day/night $45/MWh day and $15/MWh night;
- Night plus boost $28/MWh;
- Controlled $31/MWh;
- Anytime $38/MWh; and
- All inclusive $35/MWh.

	high	shoulder	low	total
TOTALS				
- MWh	**10,000**	**20,000**	**70,000**	**100,000**
- overall profile	**10%**	**20%**	**70%**	
NIGHT-ONLY				
- hours available per day	**0**	**0**	**8**	
- proportion of period available	**0%**	**0%**	**44%**	
- proportionate profile	**0%**	**0%**	**100%**	
- usage	**0**	**0**	**5,000**	**5,000**
- proportion usage in each period	**0.0%**	**0.0%**	**7.1%**	
- revenue	**0**	**0**	**75,000**	**75,000**
- $/MWh				**15**
Residual Profile	**8984**	**17968**	**57048**	**84000**
Proportionate Residual Profile	**11%**	**21%**	**68%**	
NIGHT PLUS BOOST				

		high	shoulder	low	total
- $/MWh		**100**	**75**	**15**	
- revenue					**3,550,000**
- hours available per day		**2**	**4**	**18**	
DAY/NIGHT	Assume Day load has the usual shape and includes a normal amount				
DAY	of all types of load				
- hours available per day		**2**	**4**	**10**	
- proportion of period available		**100%**	**100%**	**56%**	
- proportionate profile		**15%**	**29%**	**56%**	
- usage		**1,016**	**2,032**	**3,952**	**7,000**
- proportion of usage in each period		**10.2%**	**10.2%**	**5.6%**	
- revenue		**101,613**	**152,419**	**59,274**	**313,306**
- $/MWh					**45**
NIGHT					
- hours available per day		**0**	**0**	**8**	
- proportion of period available		**0%**	**0%**	**44%**	
- proportionate profile		**0%**	**0%**	**100%**	
- usage		**0**	**0**	**4,000**	**4,000**
- proportion of usage in each period		**0.0%**	**0.0%**	**5.7%**	
- revenue		**0**	**0**	**60,000**	**60,000**
- $/MWh					**15**
This point is w here all loads mutually exclusive to time periods end.					
Different break points can be used.					
CONTROLLED	Note an assumed portion (40%) of All Inclusive load is included here.				

NIGHT PLUS BOOST				
- hours available per day	0	2	10	
- proportion of period available	0%	50%	56%	
- proportionate profile	0%	22%	78%	
- usage	0	883	3,117	4,000
- proportion of usage in each period	0.0%	4.4%	4.5%	
- revenue	0	66,257	46,749	113,006
- $/MWh				28

CONTROLLED	Note an assumed portion (40%) of All Inclusive load is included here.			
- hours available per day	0	4	16	
- proportion of period available	0%	100%	89%	
- proportionate profile	0%	26%	74%	
- usage	0	2,616	7,384	10,000
- proportion of usage+I3 in each perioc	0.0%	13.1%	10.5%	
- revenue	0	196,219	110,756	306,975
- $/MWh				31

Could make a new residual profile here then profile Day / Night load here (Anytime shape).

ANYTIME				
- proportionate profile	13%	21%	66%	
- usage	8,984	14,468	46,548	70,000
- proportion of usagein each period	89.8%	72.3%	66.5%	
- revenue	898,387	1,085,105	698,221	2,681,713
- $/MWh				38

ALL INCLUSIVE (60% anytime, 40% controlled)				
- $/MWh				35

Annex 4 – LECG Paper

Incremental cost measures and pricing

To the Pricing Approaches Working Group

Stuart Shepherd

21 June 2004

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1 Introduction

Some submitters on the 23 May 2003 draft consultation paper from the Pricing Approaches Working Group (PAWG) raised the issue of the desirability, from an economic efficiency perspective, that distribution prices reflect the incremental (or marginal) costs of supplying the service. A paper addressing this issue was prepared by Charles River & Associates (CRA) for the Energy Efficiency and Conservation Authority.[19] Subsequently a paper prepared for the Independent Pricing and Regulatory Tribunal (IPART) of New South Wales, dealing with the same issue, has been brought to PAWG's attention.[20]

This report summarises the issues raised, discusses various measures of incremental and average cost, and considers what methods in practice are usually used in regulatory settings to reflect incremental costs in prices.

2 Nature of issues raised

2.1 CRA paper

CRA's paper made the following points:

"There are legitimate reasons for distributors to adopt different charging structures. Economic efficiency considerations suggest that depending on network (or part of network) utilisation rates, distribution charges should be set to:

- *limit the influence of distribution charges on customer behaviour when capacity is sufficient to meet existing loads and forecast loads over the network planning horizon. This implies greater use of fixed charges where possible and relatively flat pricing approaches;*
- *encourage customers to make cost effective investments in demand-side management, energy efficiencies and distributed generation when capacity is constrained or is likely to become constrained over the network planning horizon. Charges should be structured so that a greater proportion of revenues are recovered through peak demand charges based on long-run marginal costs of network augmentation, or from domestic and small commercial customer's uncontrolled loads through higher variable charges;*

Although diverse charging structures imply increased complexity and administrative costs for retailers, this should not unduly restrict distribution pricing approaches that aim to encourage efficient customer decision-making. Dynamic efficiency gains are likely to swamp the extra transaction costs. While inevitably there must be some form of averaging

[19] "Model approaches to distribution pricing: Submission to PAWG", Charles River & Associates, pp 2-3.

[20] "Reducing regulatory barriers to demand management", by Sinclair Knight Merz and M-co, November 2003.

and uniformity of pricing approaches across customers and geographic regions, in order to keep administrative costs manageable, ultimately it is for distributors to determine the extent of averaging given the costs and potential benefits of more efficient tariff structures; and

ICP and GXP based pricing approaches appear to be reasonable approaches to recovering distribution charges, and both appear to be capable of providing economically efficient pricing signals. Distributors, however, must recognise that with GXP pricing approaches the potential gains with sharper pricing incentives (e.g. peak load pricing for profiled loads) may not be any greater than under an ICP-based approach. Retailers are still constrained by customer meter type. Although GXP-based approaches create a greater incentive for retailers to roll out time-of-use meters to small customers, given the low margins involved in retailing, and short-term relationships retailers may have with customers, the incentive may still not be sufficiently strong. ICP-based approaches have the advantage that distributors can more readily set the structure of tariffs, rather than rely on retail competition to directly reflect distribution charges to end-use customers."

The key points from the above are, from an economic efficiency perspective, prices should reflect forward-looking incremental costs, the extent of those costs will vary with the degree to which the network is congested or forecast to be congested, and there are practical constraints to the extent to which such prices can be implemented that include transactions costs and the availability of information (e.g. due to the absence of time of use meters). These propositions are widely accepted.

The CRA report, in section 5, illustrates the same point with a stylised view of an electricity network cost structure where the supplier faces a single and very large incremental cost. This reinforces the general theoretical points noted above, but of itself does not provide additional guidance on pricing as it does not take into account practical issues that lines businesses must resolve when setting prices. In particular the main deficiency of such a stylised approach is that it does not recognise that networks are seldom replaced as a single event and that the incremental costs of relieving congestion are rarely charged to the particular consumer that gives rise to the congestion.

2.2 IPART paper

PAWG was also referred to a paper prepared for the Independent Pricing and Regulatory Tribunal (IPART) of New South Wales.

That paper similarly sets out the desirability of prices signalling incremental costs, but recognises to a greater extent some of the practical difficulties of achieving such an outcome.

3 Various measures of cost

Costs can be measured in a number of ways, relative to a change in the quantity of goods or services supplied. Some of the commonly used measures are:

Incremental (or marginal) cost (IC), which refers to the cost faced by a supplier to provide another increment of product or service. In order to calculate an incremental cost one needs to first define the increment. In an electricity network an increment could be one of a number of different units, for example:

- The connection of an incremental consumer to the network who is located close to the network (which may or may not be congested)
- The connection of an incremental consumer to the network who is located some distance from the network (e.g. in a new subdivision), and the existing network may or may not be congested.
- The connection of a whole new subdivision to the network.
- The demand on the network of an incremental kW or MW (where the network may or may not be congested).
- The total set of services being provided by the network.[21]

Thus in order to be able to apply the incremental cost concept in any particular context the increment which is being costed must first be defined.

Long run incremental cost (LRIC), which refers to all costs incurred by the supplier over the long run to provide the increment. "Long run" is usually defined relative to the period over which all assets required for the production of the increment are replaced.

Short run incremental cost (SRIC), which refers to the costs incurred in the short run to supply the increment. "Short run" is defined as some period shorter than "long run", that is some period shorter than that required for all assets to be replaced.

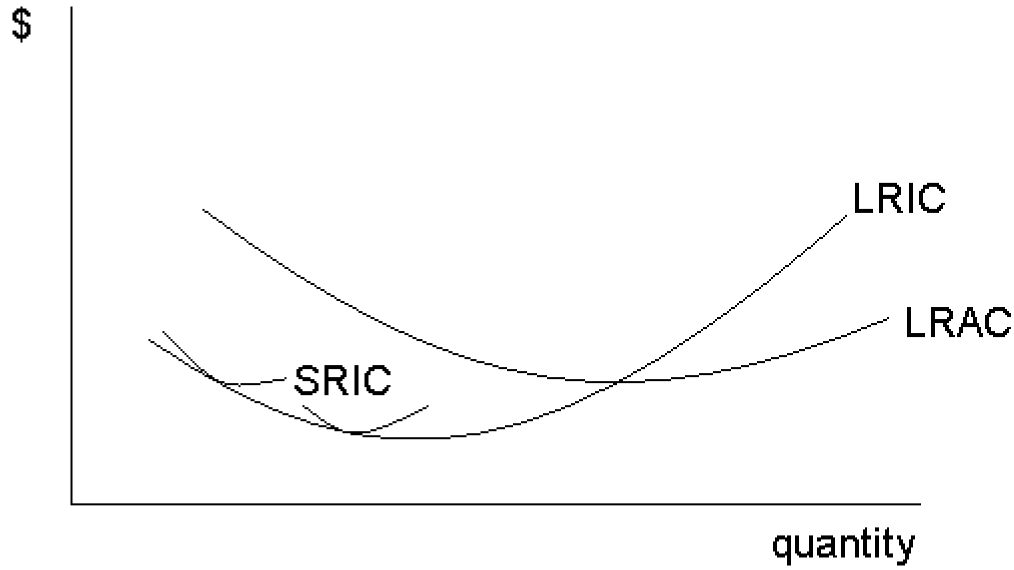
Average cost (AC), which refers to the total costs incurred by the supplier of a set of goods or services, divided by the number of units of that good or service.

Long run average cost (LRAC), which refers to the total costs incurred by the supplier over the long run to provide a set of goods or services, divided by the number of units of that good or service. "Long run" is usually defined relative to the period over which all assets required for the production of the increment are replaced.

Short run average cost (SRAC), which refers to the total costs incurred by the supplier over the short run to provide a set of goods or services, divided by the number of units of that good or service. "Short run" is defined as some period shorter than "long run", that is some period shorter than that required for all assets to be replaced.

The graph below illustrates graphically three of these costs measures that are often used – SRIC, LRIC and LRAC. One point to note is that LRAC rises where LRIC is above LRAC, and reduces where LRIC is below LRAC.

[21] In telecommunications regulatory hearings this increment is often referred to as "Total Service", as part of Total Service Long Run Incremental Cost, or TSLRIC.



In practice, for a particular electricity network, and given the geographical location of a set of customers, the LRIC and LRAC measured with respect to increasing network capacity are likely to be relatively linear and downward-sloping, reflecting that there are economies in providing more capacity to the same customer group (i.e. there are economies in energy density).

3.1 Practical issues of using cost measures in pricing

There are a number of practical issues when reflecting incremental cost in prices that lead usually to the use of some form of average cost rather than a strict incremental cost:

- It is very unusual for prices to reflect the cost of the last single unit of output (e.g. the person who triggers the need for an additional plane on a route paying the costs of operating that additional plane). What is more usual is that prices reflect some average cost of producing output from the incremental (or marginal) production unit (e.g. the incremental plane or generation plant). Charging incremental cost in the strict sense is usually very difficult and impractical to implement (e.g. to identify which consumer triggered the need to invest), and would be widely perceived as inequitable.

- The information required to implement incremental costs in prices may not be available readily. One example of this (and noted in the CRA report) is the absence of time-of-use metering data for residential consumers, which would be required in order to charge these consumers a differential peak rate for their electricity usage at times when the network is congested.

- A pricing scheme that reflects strict incremental costs is likely to be complex, costly to implement, and confusing to consumers. If in practice consumers choose to not make the effort to understand the pricing structure they face, or respond to it, then the costs of implementing complex pricing structures are questionable. In practice a small number of easily understood pricing signals, that reflect key cost drivers to supply the service (e.g. congestion times on the network), are likely to be the most efficient.

- One important feature of efficient pricing is that prices are set at a level which provides sufficient revenue such that investors have financial incentives to invest in supplying the service, which requires that investors can expect to obtain at least a normal return on their investments. Where incremental costs are below average costs, pricing at incremental cost only (i.e. using no other tariffs such as a fixed fee) will not provide an adequate return on investment. Full average cost pricing (i.e. incorporating all costs in the average) enables the supplier to obtain a return on its investment.

3.2 General practice in cost-based pricing

In jurisdictions where the regulator bases prices explicitly on cost estimates for providing the service (e.g. in Australian states), the usual cost measure to set the "revenue requirement" is one of total long run costs (with the asset base measured on an optimised depreciated replacement cost, or ODRC, basis). These total costs are then recovered from consumers in some averaged manner, resulting in some form of LRAC being reflected in prices.

Similarly, in telecommunications regulatory proceedings (e.g. in Australia and the US) costs for pricing purposes are measured typically using the Total Service Long Run Incremental Cost (TSLRIC) method.[22] This method incorporates all costs required to provide a defined service, and in practice converges with LRAC for the defined service.

Orion's pricing approach is often referred to as an incremental cost approach to pricing. However, it can be seen from the calculations used to derive the prices for peak periods (appended) that it is strictly an LRAC approach (it uses the average cost to provide additional capacity in the Orion network). This is not to say that this pricing approach does not achieve its desired aim of signalling the costs of congestion, but rather that it signals the average costs of congestion to all those operating in peak periods, and not strictly the incremental costs of congestion to the particular consumers that give rise to the congestion. It is common to use this averaged approach to congestion pricing in network services (e.g. in telecommunications networks, congestion pricing in roading, and so forth).

[22] For an explanation of TSLRIC see "TSLRIC, TELRIC and other forms of forward-looking cost models on telecommunications: A Curmudgeon's guide", Henry Ergas, Centre for Research in Network Economics and Communications, University of Auckland, November 1998

As LRAC refers usually to a given increment in capacity or a specific service, then the term Long Run Average Incremental Cost (LRAIC) is probably the best description of the cost concept that would fit the objectives of the PAWG report.

4 Conclusions

Some submitters have raised with PAWG the desirability (from an economic efficiency perspective) that the model pricing approaches developed by PAWG incorporate pricing that reflects the incremental costs to supply the service. This desirable feature in pricing is accepted.

Given practical issues that must be resolved in pricing in the context of electricity distribution, prices that aim to reflect the incremental cost to supply the service will generally reflect some form of long run average cost to supply the service, or a form of long run incremental cost that is defined in such a way as to be equivalent.

Appendix – Orion pricing method

Extract from "Derivation of electricity delivery prices from 1 April 2003", Orion, 27 June 2003

"3.1 Peak Component

The peak component signals the incremental cost to provide capacity when the distribution network is operating at peak loading. The rationale for this component is that the investment in networks is primarily determined by the maximum power loading on the network. This is generally applicable to both distribution and transmission networks.

The average incremental cost for the whole network is derived as follows:

Distribution network Optimised Replacement Value (ORV), including spares, as at 31 March 2002	*$822m*
Orion network maximum load	*550MVA*
Average cost per kVA peak load to replace distribution network	*$1,495/kVA*
Proportion of investment which is load-dependent	*46%*
Hence, cost of load-dependent ORV at peak loading is	*$688/kVA*
Equivalent annual cost applying at GXP (refer below)	*$96/kVA/yr*

Based on a post-tax return of 8%, depreciation based on a 50-year life and operating and maintenance costs averaging 2.1% of replacement value, the replacement cost of $688/kVA is equivalent to an annual cost (i.e. annuity or capital recovery) of $96/kVA/year."