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# Use-of-System Pricing Methodology

Effective: 1 April 2015

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# 1 Changes to Pricing Methodology

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There has been no material change to Aurora's pricing methodology since last publication; however, changes to price quality regulation<sup>1</sup>, promulgated by the Commerce Commission, have seen some change in terminology, and have changed the manner in which some costs are recovered. This is further explained in section 1.1, below.

## 1.1 Price Path Reset

On 28 November 2014, the Commerce Commission (the Commission) released its final decision on the reset of default price-quality paths for non-exempt distributors, including Aurora. Arguably, one of the most significant features of the Commission's decision is the requirement to separate distribution prices from prices designed to recover pass-through and recoverable costs. Effectively, the Commission has created two separate price paths:

- (1) A distribution price path designed to allow distributors to recover the costs of owning and operating a distribution network, including a regulated return on investment. Prices are set by allocating allowable notional revenue across quantities that are lagged by two years.
- (2) A pass-through price path designed to allow distributors to recover costs that it generally (1) cannot predict with any accuracy at the time prices are set, and (2) cannot control. Prices are set by allocating pass-through and recoverable costs across current quantities, including a forecast for quantity growth during the 12-month pricing period, where this is appropriate. The distributor must publish, annually, the pass-through balance at the end of the pricing year, and is required to adjust pass-through pricing by adding or subtracting (as appropriate) the most recent known pass-through balance, adjusted for the time-value-of-money at the regulated cost-of-debt.

This has seen Aurora change its terminology for its pricing components. Whereas pricing components were formerly categorised as either "distribution" or "transmission", the pricing components are now categorised as "distribution" or "pass-through".

This change has also seen an adjustment in the manner in which some costs are recovered. Whereas, previously, transmission price components solely recovered transmission costs, the new pass-through price components now recover some costs that were previously recovered in distribution price components. Pass-through price components are more explicitly described in section 5.2.

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<sup>1</sup> Commerce Commission. 2014, Electricity distribution services default price-quality path determination 2015.

## 2 Introduction

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As a supplier of an essential service, Aurora intends to set fair and reasonable prices for the specific individual demands of small, large and seasonal electricity users having shared access to Aurora's network.

### 2.1 Purpose

This document outlines the pricing methodology Aurora uses to determine its use-of-system charges (line charges).

### 2.2 Consumer Consultation

Aurora regularly seeks the views of consumers through a range of survey mechanisms. In general, survey results indicate that:

- Consumers still consider price to be more important than quality of supply, and that there is little appetite to accept an increase in line charges to achieve a proportionate improvement in quality; and
- The frequency of interruptions remains the single most important issue relating to quality of supply.

It is recommended that interested persons wishing to understand more about Aurora's consumer consultation approaches and subsequent analysis refer to the detailed analysis contained in Aurora's annual Asset Management Plan, available from the Information Disclosure section of the Aurora website – [www.auroraenergy.co.nz](http://www.auroraenergy.co.nz).

Overall, Aurora considers that its current approach to pricing reflects the concerns of consumers and other stakeholders and ensures that sufficient revenue is generated in order to meet future asset improvement programmes.

### 2.3 Characteristics of Aurora's Distribution Network

Aurora is served from five GXPs; three in Central Otago and two in Dunedin. Due to their relatively homogenous characteristics, the Dunedin GXPs of South Dunedin and Halfway Bush form a single pricing area, as do the Central Otago GXPs of Clyde and Cromwell. Figures 1 to 3, below, show the geographic arrangement of each pricing area. Aurora also operates a small embedded network (residential subdivision) at Te Anau, which takes supply from The Power Company network.

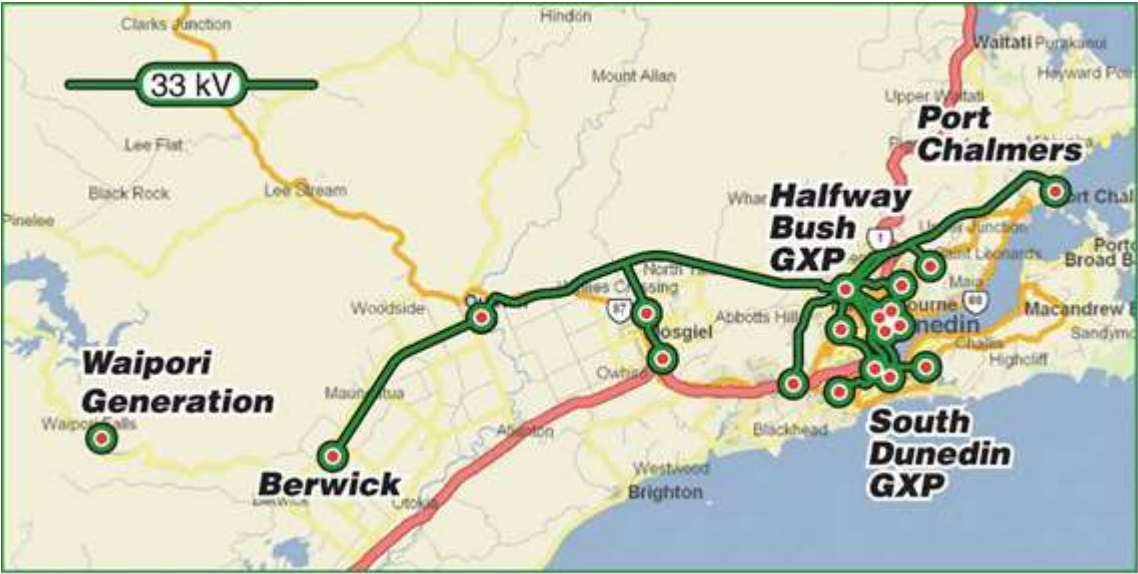


Figure 1 - Dunedin Pricing Area - South Dunedin and Halfway Bush GXPs



Figure 2 - Clyde / Cromwell Pricing Area - Clyde and Cromwell GXPs



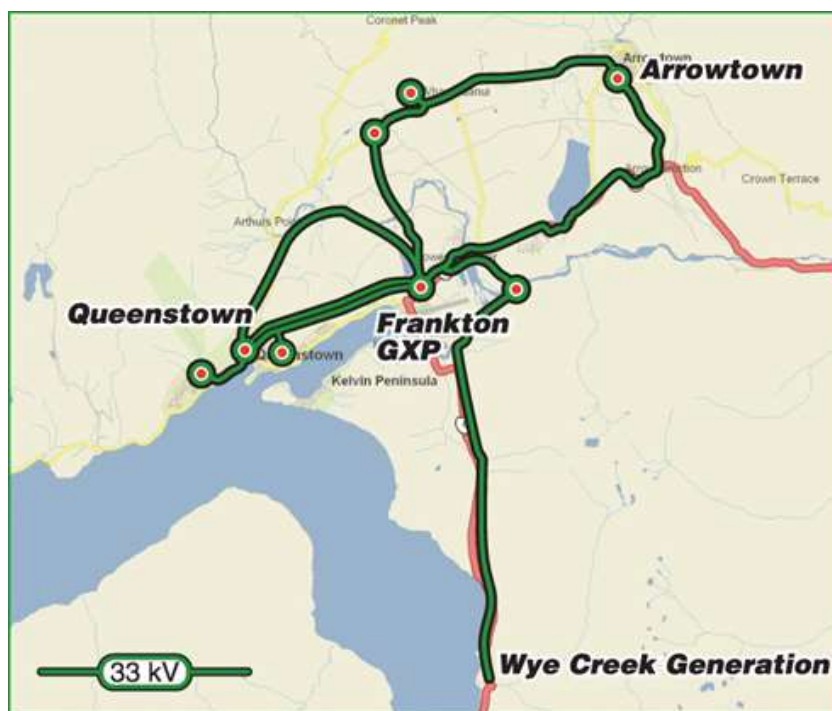


Figure 3 - Frankton Pricing Area - Frankton GXP

## 2.4 Pricing Methodology Requirements

The Electricity Industry Act 2010 provides for the Electricity Authority to set pricing methodologies and disclosure requirements for Electricity Distribution Businesses (EDBs). In February 2010, the Electricity Authority, through its predecessor the Electricity Commission, published Pricing Principles and Information Disclosure Guidelines for Aurora and other EDBs to follow in relation to their pricing methodologies.

The Commerce Commission also has the mandate to promulgate similar requirements under Part 4 of the Commerce Act 1986 – except where another industry regulator (such as the Electricity Authority) has the power to set pricing methodologies in relation to particular goods or services<sup>2</sup>. The Commerce Commission has accordingly determined that it is not required to set an Input Methodology for pricing methodologies for electricity distribution services. However, the Commerce Commission previously endorsed the principles based approach adopted by the Electricity Authority in its consultation on its Pricing Principles.

In addition to the Electricity Authority's Pricing Principles and Information Disclosure Guidelines, the Commerce Commission continues to have regulatory jurisdiction for pricing methodology disclosures<sup>3</sup>. These requirements are set out in Clauses 2.4.1 to 2.4.5 of the Electricity Distribution Information Disclosure Determination 2012, published by the Commerce Commission.

<sup>2</sup> See section 52T(1)(b) of the Commerce Act 1986.

<sup>3</sup> See section 53C(2)(c) of the Commerce Act 1986

## 2.5 Pricing Principles

The current approach is for Aurora and other EDBs to set pricing methodologies that are consistent with the following Pricing Principles:

- (a) Prices are to signal the economic costs of service provision by:
- i) being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulation and/or the Government Policy Statement;
  - ii) having regard, to the extent practicable, to the level of available service capacity; and
  - iii) signalling, to the extent practicable, the impact of additional usage on future investment costs.

*This pricing principle means that the price paid by consumers (or a class of consumer) should at least cover the additional costs of their connection to the network, but should not be any more than the cost of building a new network dedicated to their requirements. On this basis, when consumers pay the variable costs attributable to them and some contribution to the fixed costs of the service they receive, then there is no subsidy provided from one consumer (class) to another. Where network capacity is limited, it is appropriate for prices to signal the costs of building new network capacity—but where the network is relatively unutilised, lower prices may increase the use of the network which reduces the overall cost per consumer.*

- (b) Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to consumers' demand responsiveness, to the extent practicable.

*This pricing principle recognises that prices, in all cases, should recover the variable costs of providing the network service to a consumer (or consumer class). To recover the total cost of the network service, the fixed costs must also be recovered from some (or all) consumers (or consumer classes). These fixed costs should be included in the prices of consumers whose demand for electricity is less sensitive to price. In this way the use of the network capacity and the cost per consumer is optimised.*

- (c) Provided that prices satisfy a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to:

- i) discourage uneconomic bypass;
- ii) allow for negotiation to better reflect the economic value of services and enable stakeholders to make price/quality trade-offs or non-standard arrangements for services; and
- iii) where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives (e.g. distributed generation or demand response) and technology innovation.

*This pricing principle recognises that, in order to be pragmatic, a pricing methodology is intended to have general application to broad consumer classes rather than to individual consumers. In addition, a practical approach is required when applying a pricing methodology so that it will not result in perverse outcomes—for example, where it is cheaper for individual consumers to seek inefficient alternatives, or where existing prices may preclude an overall more efficient solution from being implemented.*



- (d) Development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact on stakeholders.

*This pricing principle recognises that consumers have made investment and/or consumption decisions on the basis of expectations that have been shaped from past pricing arrangements. Wherever possible, any material changes to pricing should be signalled in advance, and their implementation should be phased in over time.*

- (e) Development of prices should have regard to the impact of transaction costs on retailers, consumers and other stakeholders and should be economically equivalent across retailers.

*This pricing principle recognises that simpler pricing arrangements and tariff structures can lower the administration and compliance costs of retailers - which can lower retail costs and lower barriers to entry for competing retailers. This is of ultimate benefit to end consumers.*

## 2.6 Compliance with Pricing Principles

Aurora believes that its current pricing methodology, as set out in the following sections, fully complies with the Electricity Authority's Pricing Principles. In particular:

- Pricing Principle (a) Signalling Economic Costs

Aurora's prices reflect cost causality in that different pricing regions have been identified to address the actual and significant regional cost variation in supplying consumer connections<sup>4</sup>. Further, as part of its approach to setting prices, Aurora places consumers in load capacity groups, with each group's charges varying according to their respective use of different types of assets.

With the exception of subsidies provided in part by compliance with the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004, Aurora's prices are subsidy free. Prices are considered subsidy free if they result in revenue that is sufficient to recover incremental costs without over-recovering standalone costs. Aurora notes that this potentially provides a wide range for prices. The use of an Assessed Capacity charge ensures prices have regard to the level of available service capacity, and similarly, the use of a Control Period Demand charge ensures that prices signal the impact of additional usage on future investment costs.

It is Aurora's intention that these charges, in combination, should promote the efficient utilisation of the network's available capacity. Where new investment is required, it is also common for Aurora to require those users who obtain the benefit to contribute towards the cost.

- Pricing Principle (b) Ramsay Pricing

Aurora recognises that some sophistication in the recovery of its total costs - which include both incremental and sunk components - can facilitate the retention and expansion of its consumer connection base, and this may, *inter alia*, lead to greater efficiency and lower overall costs per consumer. Aurora intends that its prices should recover the incremental costs of its service delivery from all consumers, and that all consumers should contribute to the recovery of sunk costs.

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<sup>4</sup> Aurora has adopted regional pricing on the grounds of cost reflectivity, and not because it regards that pricing on a regional basis to be a significant factor in influencing the locational decisions of its consumers.

There is a risk that Aurora will under-recover its total costs. The Electricity Authority's Pricing Principles recognise that it is not unreasonable for any shortfall in cost recovery to be recovered from those consumers with lower elasticity of demand. However, Aurora has not segmented its consumers by demand responsiveness (elasticity). In fact, Aurora believes that any economic benefit from a strict application of Ramsay Pricing<sup>5</sup> will be lost to the increased compliance costs and potential barriers to retail competition as a consequence of additional tariff classes (i.e. further consumer segmentation). So, while Aurora has a policy of subsidy free prices, it also has regard to customer demand elasticity through the tariff structure – e.g. the fixed and variable components of the tariff. In this regard, the fixed costs of service delivery are recovered from consumers using different mechanisms.

For large consumers, fixed costs recoveries are based on a consumer's demand and capacity characteristics - which tend to be fixed in the short term but can be influenced by consumers taking appropriate periodic actions. For domestic consumers, these fixed cost recoveries tend to be 'variable' on the basis of kWh consumption, as Aurora is limited to a large extent by Government Policy on the level of fixed charges for domestic customers (i.e. the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004).

- Pricing Principle (c) Responsive to Stakeholder Requirements/Circumstances

Aurora supports the Pricing Principles, as they are aligned with its commercial imperatives. For instance, cross-subsidisation may in the long-term expose Aurora to loss from each new consumer connection in a cross-subsidised load group. In addition, Aurora recognises that over-pricing engenders the commercial risk (as well as the economic inefficiency) of bypass. To minimise the risk of uneconomic bypass, Aurora's pricing methodology specifically includes a kVA-km tariff component<sup>6</sup> and, if required, allows for prudent discounts. Given the significant commonality of costs for all consumers using its network, Aurora regards the receipt of discounted revenue (providing it covers the variable cost and contributes something to fixed costs) to be in the interests of all parties. However, Aurora fully supports investments in innovative technologies, demand response, and distributed generation where these provide an efficient alternative to 'traditional' distribution.

A level playing field is necessary to ensure that any party, including Aurora, has appropriate incentives for efficient innovations. The control period demand component of Aurora's tariffs provides a very strong signal for the investment in distribution alternatives.

Aurora is prepared to negotiate non-standard arrangements with consumers, and in particular, Aurora provides the ability for consumers to pay for enhanced reliability through additional or higher specification equipment.

- Pricing Principle (d) Regard to Stakeholder Impacts

It is important that the pricing methodology should avoid both price discrimination and incentives for inefficient behaviour. An example of the latter is where pricing may provide an artificial incentive for consumers to change load groups to obtain an overall lower cost of service.

Aurora is cognisant of the impact of its prices on its stakeholders (including retailers and electricity consumers). Whilst electricity delivery prices form a minor component of retail electricity prices, Aurora believes that its pricing methodology is sufficiently transparent to allow stakeholders make informed decisions concerning the delivery costs associated with their location and demand/consumption of electricity.

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<sup>5</sup> Ramsay pricing is a form of price discrimination which concerns the prices a monopolist should set in order to maximise societal benefit. Where differential pricing is appropriate, then arguably the highest prices should be borne by those consumers with the most inelastic demand—as their consumption is least likely to be distorted as a result.

<sup>6</sup> The kVA-km component only applies to larger connections in deference to the Government's desire that prices for small rural connections are similar to those for small urban connections in the same region.

Aurora's price structure has been very stable with little change since 1993 (Dunedin) and 2003 (Central Otago). Some minor refinements have occurred – such as the introduction of the kVA-km tariff component in 1996. At the time Aurora ensured a phasing-in of this tariff component to minimise the impact on remote connections.

- Pricing Principle (e) Regard to Downstream Competition Impacts

Aurora's tariffs do not favour one retailer more than another. All retailers (and direct connect consumers) pay the same 'distribution price' irrespective of what retailer supplies the energy. This is important to ensure that retailers can compete on a level playing field. However, Aurora is also cognisant that downstream retail competition may be stifled/impeded by numerous or overly complex tariff structures.

Aurora believes the pricing methodology it has adopted provides a reasonable balance between cost reflectivity and the number of tariffs. Any cost reflectivity benefit from additional tariff disaggregation is likely to be outweighed by the negative impact this would have on retail competition (i.e. the prospect of complex tariff structures may be a disincentive to new entrant retailers).

## **2.7 Compliance with Electricity Authority Information Disclosure Guidelines**

Aurora considers that the following sections address the disclosure requirements set out in the Information Disclosure Guidelines promulgated by the Electricity.

In publishing its pricing methodology, Aurora has sought to explain:

- How the methodology links to the pricing principles (Section 2.4)
- The rationale for consumer groupings and the method for determining the allocation of consumers to the consumer groupings (Sections 4 and 5)
- Quantification of key components of costs and revenues (Section 4)
- An explanation of the cost allocation methodology and the rationale for the allocation to each consumer grouping (Sections 3 and 4)
- An explanation of the derivation of the tariffs to be charged to each consumer group and the rationale for the tariff design (Section 5).

### 3 Aurora's Approach to Pricing

Aurora's pricing methodology articulates a rational basis for setting prices for individual consumer connections. As recognised in the Pricing Principles, cost causality provides an efficient basis for linking the price paid by consumers to the cost of the services provided. Under a cost causality approach, the pricing methodology must identify an efficient basis for allocating the cost based revenue requirement. It must also identify the drivers of cost. As depicted in Figure 4, below, the revenue requirement is first allocated to distribution services, so the cost of providing particular services can be ascertained. Cost drivers, representing the extent to which various consumers cause (or contribute to the causation of) these costs in their use of these services, provide the basis for pricing.

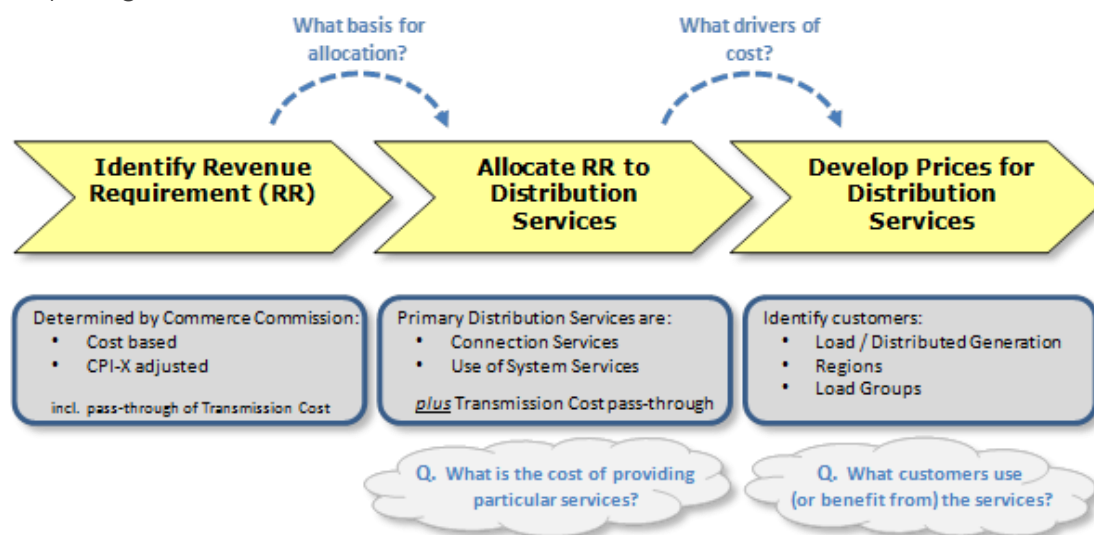


Figure 4 - Pricing Process

The application of this process in Aurora's pricing methodology is expanded on below.

#### 3.1 Description of Aurora's Pricing Methodology

Figure 5 summarises the major elements and options that need to be reviewed/considered as part of Aurora's pricing methodology. They include:

- the revenue requirement
- the allocation of the revenue requirement to services (e.g. connection services and shared use-of-system services)
- the allocation of 'use-of-system' cost recoveries (and also transmission costs<sup>7</sup>) between generation and loads; and
- the allocation of load 'use-of-system' costs (and transmission costs) between load customers AND the allocation of generation 'use-of-system' costs (and transmission costs) between generators.

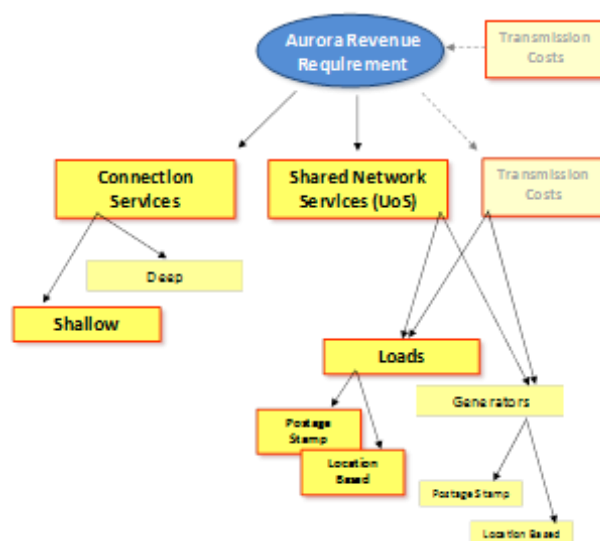


Figure 5 - Pricing Considerations

<sup>7</sup> Transmission costs do not include 'Loss and Constraint Rental Rebates' which are credited separately. HVDC charges, however, are recovered directly from distributed generators (refer also to Schedule F)

### 3.1.1 Revenue Requirement

To remain viable, Aurora must obtain sufficient revenue to:

- (a) meet its contractual obligations for connection to the Transpower grid;
- (b) meet its contractual obligations for delivery of energy over the distribution network;
- (c) comply with statutory requirements on public safety, environmental protection and quality of supply; and
- (d) provide a commercially appropriate return on funds.

The Commerce Commission asserts regulatory control over Aurora's revenue from distribution services. This is in the form of a CPI-X weighted average price control that is periodically reset to ensure, *inter alia*, that Aurora does not systematically derive excessive profits but has sufficient incentive for on-going investment in its network.

The revenue requirement is based on Aurora's efficient costs (including its cost of capital). Aurora's efficient costs are detailed in Section 4.4 below.

### 3.1.2 Allocation of Revenue Requirement to Services

Aurora's services primarily include connecting consumers to its network, and providing shared use of (i.e. access to) its network for the conveyance of electricity. This dichotomy is widely recognised in transmission pricing. In recognising that Aurora does provide both connection and use-of-system services, it must also be recognised that connection services at the distribution level tend to be of a lesser order of magnitude than connection services at the transmission level. However, distribution connection costs tend to be more significant for larger consumers where specialist and/or dedicated assets are required.

As part of the pricing methodology it is necessary to determine the extent to which Aurora's efficient costs<sup>8</sup> should be allocated to:

- (a) dedicated Connection services; and/or
- (b) shared use-of-system services.

There is no 'right' allocation, and the spectrum of possibilities is depicted in Figure 6, below.

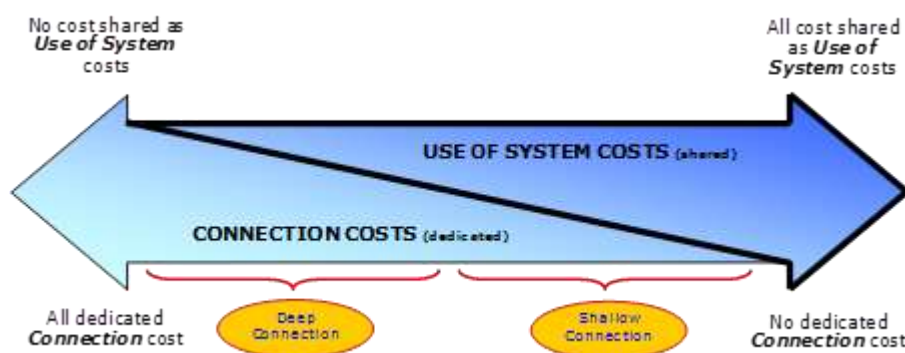


Figure 6 - Cost Allocation

<sup>8</sup> Transmission costs have been ignored in this discussion of allocating the revenue requirement, as they are recoverable costs, and Aurora treats transmission costs in a similar manner to 'use-of-system' costs.

In many respects, Aurora's revenue is not directly affected by the allocation of cost to connection and/or use-of-system services. However, new and existing consumers, the local economy, and therefore (indirectly) Aurora may be affected by such allocations. Other factors considered by Aurora include:

- Price stability ... consumer prices will be more stable over time (i.e. less subject to changes in flows, demand, new investment, etc.) if the revenue requirement is recovered through a mix of dedicated and shared costs
- Revenue at risk ... it is less risky for Aurora if a portion of its revenue requirement is fixed rather than variable
- Economic signals ... connection charges (especially deep connection charges) will provide locational signals<sup>9</sup>.

Moving along the spectrum of recovering dedicated-versus-shared costs will have an impact on prices and on consumers. Aurora seeks to avoid the entire revenue requirement being averaged/spread over distribution consumers with no recognition of who may be a causer of the cost or a beneficiary of the service. In this regard, Aurora has considered the implications of moving from no dedicated connection charges (i.e. all costs recovered as use-of-system charges) through to shallow connection charges (i.e. mostly use-of-system charges) through to deep connection charges (i.e. few shared costs to be recovered as use-of-system charges), and has determined the following:

- Aurora will continue to apply a shallow connection policy, with the majority of its efficient costs being recovered through use-of-system charges. Exceptions apply in the case of:
  - Distributed Generation – where prices will reflect the dedicated assets used to connect generation to Aurora's network and the principles of cost recovery in Part 6 (Connection of Distributed Generation) of the Electricity Industry Participation Code 2010 and subsequent amendments.
  - Customer Contributions – Aurora will continue to seek contributions from customers whose connections require specialist or dedicated equipment, or where use-of-system charges do not fund the costs of upstream additional assets for the new connection or in cases where Aurora considers its risk of asset stranding is high.
  - Costs allocated to the use-of-system service will those efficient costs remaining after connection charges and/or customer contributions have been taken into account.

### **3.1.3 Allocating Use-of-System Costs between Loads and Generation**

After deducting connection charges, Aurora's policy is to allocate the remaining use-of-system cost to load customers. As noted above, Aurora already charges generation customers for the dedicated assets used to connect generation to Aurora's network.

### **3.1.4 Allocating Use-of-System Costs between Load Customers**

As a supplier of an essential service, Aurora intends to set fair and reasonable prices. Delivery charges as a whole are cost-based and the recovery of those costs will be spread fairly over users of the network. To the extent possible, Aurora will directly attribute costs to consumer groupings. Remaining costs need to be allocated as fairly as possible. The application of fairness to delivery pricing is one of the most difficult objectives to achieve, because users have varying views on what is fair - based to a large extent on how the pricing methodology impacts on their individual line charges.

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<sup>9</sup> For instance, new load customers may be attracted to locations where the existing connection infrastructure has lower costs.



The costs of service delivery on Aurora's networks vary by location. Accordingly, Aurora disaggregates its network into pricing areas, and costs are attributed to these regions so as to more fairly reflect the locational costs of service delivery. This is described more fully in Sections 4.1 to 4.3. Consumers also use the system differently. In particular, large consumers have proportionately greater recourse to the high voltage network elements than smaller consumers. Again Aurora takes this into account in its pricing methodology by establishing load groups and allocating the (regional) revenue requirement to these load groups proportional to their differentiated use of the system's assets. This is described more fully in Section 4.5. Aurora's approach means that prices may differ between pricing areas, and between load groups.

Within load groups for each pricing area, Aurora adopts a tariff structure that is intended to reflect the impact of customers' consumption (and other) decisions on the key drivers of Aurora's costs. In generic terms, costs are driven by some combination of customer numbers, electricity conveyance volumes, and (peak) capacity. However, to more accurately reflect the 'standalone' costs of each load group in pricing outcomes, it is appropriate for the cost drivers to differ as between load groups. For instance, if costs were simply allocated on a customer number (ICP) basis, then a disproportionate amount of cost would be recovered from domestic consumers. Conversely, if costs were allocated on the basis of electricity conveyed, then a disproportionate recovery from larger consumers would occur. Although larger consumers may be responsible for the overall capacity of the network, the overall length of the network tends to be a response to domestic consumer demands.

As would be expected, the load groups representative of smaller consumers are allocated costs for both the high and low voltage elements of the network, whilst the load groups representative of the largest consumers are allocated costs for the high voltage network elements only.

For larger consumers (i.e. price codes L3, L4 and L5), costs are recovered through:

- kVA capacity charges (based on assessed capacity);
- kVA-km charges (based on the high voltage circuit distance from the nearest GXP and the connection capacity in kVA); and
- kW demand charges (based on CPD).

Aurora considers that capacity, distance, and peak demand are the key drivers of cost for these consumers and therefore prices determined on this basis are reflective of the costs (particularly the standalone costs) of these larger consumer load groups (i.e. price codes L3, L4 and L5).

For smaller consumers (i.e. price codes L1 and L2), costs are recovered through:

- kVA capacity charges (based on assessed capacity);
- kW demand charges (based on assessed CPD).

Aurora considers that capacity and peak demand are the key drivers of cost for these consumers and therefore prices determined on this basis are reflective of the costs (particularly the standalone costs) of these load groups (i.e. price codes L1A, L1 and L2).

For smaller consumers (i.e. price codes L1 and L1A) which also satisfy the definition for "domestic" (refer to section 5.1.1), costs are recovered through:

- fixed charges (per ICP); and
- kWh charges (based on periodic consumption).

This price structure for smaller domestic consumers is not Aurora's preferred recovery mechanism, but has been partially forced upon Aurora in order to comply with Government Policy as to the level of fixed charges (as per the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004). These regulations require domestic consumers using up to 9,000 kWh per annum to have, as an option, the fixed portion of their line charges limited to 15 cents per day. This has been applied to the recovery mechanism used for costs in load groups L1 and L1A only. This price structure nonetheless signals some of the peak demand cost drivers for these smaller domestic consumers, with the main weakness being that actual capacity costs are not recovered from consumers that use low kWh volumes. This weakness is increasingly being exacerbated by the deployment of Small-Scale Distributed Generation (SSDG), and is also giving rise to issues of equity, since consumers that can afford SSDG systems inevitably shift the burden of network cost recovery to consumers that cannot afford such systems.

The determination of load groups and the structure of load group prices for each pricing area are detailed more fully in Sections 4 and 5 respectively.

### 3.2 Pricing Strategy

The Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 requires that, where EDBs have a pricing strategy, they must:

- explain the pricing strategy as it applies to the current disclosure year, and for the subsequent five disclosure years.
- explain how and why prices set for each consumer group are expected to change as a result of the pricing strategy.

Pricing strategy is defined in the Determination as "a decision made by Directors of the EDB on the EDB's plans or strategy to amend or develop prices in the future, and recorded in writing". Aurora does not have a pricing strategy according to this definition; however there are a number of issues that could potentially impact on pricing and price structure in the future, which are described in brief below:

#### 3.2.1 Control Period Demand (CPD)

Aurora currently assesses consumers' contribution to Control Period Demand (CPD) following the winter months of May to August, annually. Electricity retailers are notified of the revised CPD quantities in late September, with the revised values applying from 1 December. The current approach is described more completely in section 5.1.2.4.

The assessed value of CPD is used to allocate distribution and pass-through costs to consumers. The introduction of the new "Pass-through Balance" under the DPP causes the timing of the application of reviewed CPD quantities to be problematic. Revising CPD quantities part-way through the pricing year may give rise to Aurora reporting a relatively large Pass-through Balance (positive or negative) at the end of the pricing year. Under regulation, the Pass-through Balance is repaid to (positive balance), or recovered from (negative balance), consumers in a future pricing period, adjusted for the time-value-of-money at the regulated costs-of-debt. It is readily foreseeable that a large Pass-through Balance may result in relatively large price changes in order to effect the repayment or recovery.

Accordingly, it is proposed to consult with electricity retailers, before May 2015, on shifting the application of new CPD quantities from 1 December to 1 April. The advantage of the proposed change in methodology to consumers is to eliminate the potential for an excessively large Pass-through Balance at the end of each pricing year and prevent price instability.

It is likely that the proposal will be attractive to electricity retailers, as it will be possible for them to advise new prices and quantities at the same time, rather than separately. It is expected that this will reduce retailers' transaction costs.

### 3.2.2 *Recovery of Interconnection Charges and Distributed Generation Allowance*

Distributors are allocated transmission interconnection charges on the basis of their contribution to Regional Coincident Peak Demand (RCPD), as determined by Transpower, and in accordance with its approved<sup>10</sup> Transmission Pricing Methodology (TPM). Aurora calculates its distributed generation allowance (formerly avoided transmission cost) on the basis of generators' injection during RDPD periods.

Transmission interconnection charges and the distributed generation allowance are currently allocated to load groups on the basis of the CPD of each load group, and recovered from individual consumers through the "Pass-through" CPD price component. Interconnection charges and the distributed generation allowance represent approximately 83% of Aurora's total transmission expense.

Aurora is concerned that its recovery approach may be resulting in two undesirable consequences:

- (1) An inequitable allocation of costs to some consumers. The current recovery method allocates the bulk of Aurora's transmission expenses to consumers with high or predominantly winter demand. Consumers with summer-only load are generally only allocated a very small proportion of transmission expenses through the "Pass-through" capacity price component.
- (2) An excessively strong peak avoidance signal, when the "Distribution" CPD price component is combined with the "Pass-through" CPD price component. Discussions with some larger consumers have raised the possibility that the price signal is driving uneconomic investment in distributed generation for peak avoidance.

As a consequence, Aurora intends to investigate whether a better method for allocating interconnection charges and the distributed generation allowance can be developed, that more fairly considers all consumers' contribution to base demand.

A potential outcome is that a greater proportion of Aurora's overall transmission expenses may be recovered through capacity prices, and a lesser proportion through CPD prices. Such an approach, if implemented, would be likely to increase charges to predominantly non-winter loads. In order to avoid price-shock to affected consumers, Aurora's investigation of the matter will consider how implementation might be staged over a number of years to avoid price shock.

### 3.2.3 *Transmission Pricing Methodology*

The Electricity Authority continues to consult with interested persons in regard to proposed changes to the Transmission Pricing Methodology (TPM).

The EA received substantial negative feedback to its 2012 consultation paper, from all sectors of the industry, including consumer groups and individual consumers. As a consequence, the EA has embarked on a programme of education and clarification; releasing a number of explanatory working papers and seeking the views of interested persons.

Although there is little evidence of the EA significantly changing its views on its proposal, the final outcome of the TPM is quite uncertain and there are inherent risks that the final approach could dilute transmission price signals and reduce price stability / certainty for consumers.

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<sup>10</sup> By the Electricity Authority.

### **3.2.4 Irrigation Contribution to Summer Peaking – Cromwell GXP**

In Central Otago, Aurora provides a controlled service for irrigation that limits pump operation to 10 hours per day during the winter months of June July and August, with the hours of operation designed to avoid times of peak demand. As a consequence, irrigation consumers utilising this service avoid both the distribution and pass-through components of CPD charges.

At the Cromwell GXP however, there is emerging evidence that indicates that irrigation demand, particularly as a result of changes in land-use (dairy conversions), may be causing a transition from winter peaking, to summer peaking. In this case, serious consideration will need to be given to the signalling of network congestion, which is likely impact on the charges that are allocated to irrigators.

### **3.2.5 Small Scale Distributed Generation**

Aurora notes an increasing trend of Small-Scale Distributed Generation (SSDG) being installed behind load at domestic installations. These connections remain connected to the Aurora network, for reasons of reliability and to transport excess energy production to the market. At the same time, there is a persisting notion across the industry, strongly influenced by regulation<sup>11</sup>, that the predominantly fixed costs of owning and operating a distribution network should be recovered from domestic consumers through variable, consumption-based, prices.

The combined effect is that consumers with grid-connected SSDG systems avoid paying their reasonable share of distribution costs (and possibly some elements of pass-through costs); effectively increasing charges to other consumers.

Aurora considers, in light of a regulatory environment that prevents widespread use of capacity-based pricing for domestic connections, that some form of export tariff should be implemented in order to ensure that consumers with grid-connected SSDG systems face charges that are more cost reflective. Aurora currently has an export tariff, for reconciliation purposes only, that is set to \$0.00, and intends to undertake further analysis within the next 12 to 24 months with a view to developing a chargeable export tariff.

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<sup>11</sup> Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004

## 4 Cost Structure

Aurora's pricing methodology is based on cost recovery. Consequently, the price structure closely relates to the corresponding cost structure. The demand/consumption and location choices of Aurora's consumers cause Aurora to incur both distribution and pass-through costs. These costs are as follows:

### 4.1 Distribution Costs

Distribution costs derive from three cost drivers.

**Asset Costs:**

- (a) provision of assets - the cost of funding including return to shareholder;
- (b) maintaining the assets to safety, legal, consumer and economic requirements.

**System Operation Costs:**

- (a) provision of fault response services;
- (b) provision of control signalling facilities to minimise investment in the transmission and distribution networks, and to provide energy retailers and their customers with a load switching services which may not relate to network investment.

**Overhead Costs:**

- (a) provision of support services related to the above items.

The variation of these costs per \$ of capacity provided for consumer use is significant between GXPs (a range from 73% to 225%), as follows:

Grid Exit Point (GXP)	ORC <sup>12</sup>	MW Peak <sup>13</sup>	ORC / MW	
Clyde	\$92,333,876	16.8	\$5,496,064	225%
Cromwell	\$149,617,147	31.6	\$4,740,721	194%
Frankton	\$132,136,176	53.7	\$2,462,654	101%
Halfway Bush	\$219,803,188	122.8	\$1,790,511	73%
South Dunedin	\$122,036,918	68.3	\$1,786,778	73%
Totals	\$717,146,454	293.1	\$2,445,357 <sup>14</sup>	100%

Table 1 - Variation of \$ORC asset per MW

<sup>12</sup> Optimised Replacement Cost (ORC) is a standardised measure of the "used and useful" distribution assets. These ORC values understate the actual replacement cost as the industry standard cost codes are based upon 2004 values plus CPI. Using actual replacement cost values would increase the overall ORC value but is not expected to significantly change the ORC/MW ratios for each GXP area.

<sup>13</sup> MW peak is the average of the 12 highest peaks

<sup>14</sup> Average

Optimised Depreciated Replacement Cost of assets has not been used in the above illustration because ORC is less susceptible to significant variation when large zone substation and transmission assets are replaced or upgraded. Older assets also generally require more maintenance and a ratio using ODRC does not appropriately reflect these higher maintenance costs.

## 4.2 Pass-through Costs

The Commerce Commission's Default Price-quality Path (DPP) regulatory regime allows Aurora to recover a range of pass-through and recoverable costs that, in general, it cannot predict with any accuracy at the time prices are set, and (2) cannot control.

The bulk of Aurora's pass-through cost is comprised of transmission-related expenses, which include direct transmission charges levied by Transpower New Zealand Limited, and avoided transmission costs (distributed generation allowance) paid to large distributed generators.

Transmission costs are determined by the Electricity Authority approved transmission pricing methodology for Transpower NZ Ltd using the following price components:

### **Interconnection Charge:**

This charge is based on the average of the 100 demands at each grid exit point at the dates and times of the highest 100 peak half hour demands for the Lower South Island region in the 12 months to 31 August prior to the pricing year beginning 1 April.

### **Connection Charge:**

This charge represents the fixed connection costs associated with the dedicated assets at each grid exit point.

The variation of these costs per MW of capacity provided for consumer use is significant between GXP (a range from 88% to 112%), as follows:

Grid Exit Point (GXP)	\$ / MW	% of average
Clyde	\$102,290	99%
Cromwell	\$91,736	88%
Frankton	\$116,673	112%
Halfway Bush	\$96,809	93%
South Dunedin	\$111,872	108%
Totals	\$103,724	100%

*Table 2 - Variation of \$ of transmission cost per MW*

Other components of Aurora's pass through costs are defined by the Commerce Commission's Input Methodologies.



### 4.3 Combined Pass-through and Distribution Costs

When the cost driver ratios are combined the following composite ratios result:

<b>GXP Area</b>	<b>Pass-through Cost</b>	<b>Distribution Cost</b>	<b>Composite Cost</b>	<b>Price Zone</b>
<i>Weighting</i>	36%	64%	100%	
Clyde	98%	225%	179%	CYD & CML
Cromwell	88%	194%	155%	
Frankton	111%	101%	104%	FKN
Halfway Bush	95%	73%	81%	HWB & SDN
South Dunedin	107%	73%	86%	
Weighted Average	100%	100%	100%	

Table 3 - Cost driver ratios

Due to the significant differences in the cost driver ratios, separate pricing areas are used. However, to reduce pricing complexity, where area costs are within 25% of an average cost, then a common average pricing structure is applied. This is a reasonable compromise between appropriately signalling the very different investment costs in each location, while keeping complexity to a minimum.

Distribution costs are, thus, predominantly related to asset value, with the result that a strict application of cost-recovery would mean that each consumer paid charges related to the assets they use. At the January 2008 Directors meeting, it was decided that pricing should move from recovering a minimum of 50% of the full delivery costs in each of the pricing areas to full recovery with transition over a number of years. This transition was completed at 1 April 2012.

### 4.4 Overall Revenue Requirements for Year Ended 31 March 2016<sup>15</sup>

Notional revenue	\$55.839 million
Pass-through costs	\$31.872 million
Transmission costs	\$23.143 million
Distributed generation allowance	\$7.256 million
Commerce Act levy	\$0.120 million
Electricity Authority levy	\$0.287 million
EGCC levy	\$0.037 million
Local Authority rates	\$1.028 million
<b>Target revenue budgeted for 2015/16</b>	<b>\$87.711 million</b>

<sup>15</sup> Derived in accordance with the Commerce Commission's Electricity Distribution Services Default Price-Quality Path Determination 2012

This revenue requirement is derived from the four pricing areas:

	Distribution	Pass-through	Total
Dunedin HB & SDN area	\$27.706 million	\$20.612 million	\$48.319 million
Central CML & CYD area	\$18.015 million	\$4.796 million	\$22.811 million
Central FKN area	\$10.047 million	\$6.465 million	\$16.512 million
Heritage Estate	\$ 0.070 million		\$ 0.070 million
Total	\$55.839 million	\$31.871 million	\$87.711 million
Weighting	64%	36%	100%

Table 4 - Revenue requirement by pricing area

These regional cost recovery requirements are further allocated to (regional) load groups as described in section 4.5, except for Aurora's 'Heritage Estate' embedded network at Te Anau, where the connection numbers (93) are so small that the breakdown by load group is less meaningful.

#### 4.4.1 Underlying Drivers of the 2015 price changes

The underlying drivers for the 2015 price change are reductions in both distribution and pass-through costs. The changes are quantified in Table 5 below:

Cost Category	Change from 2014
Notional revenue	-\$1.609 million
Pass-through costs	-\$0.572 million

Table 5 - Price change drivers

## 4.5 Load Group Characteristics and Area Cost Allocations

This section details the three step process of allocating the revenue requirement to load groups. The steps are:

- Step 1: Allocate the (regional) revenue requirement to asset classes with the return component proportionate to the ORC of that asset class.
- Step 2: Identify the extent to which each load group uses each asset class.
- Step 3: Identify the cost of the service provided to each load group.

However, before undertaking this three step process, it is necessary to first define the Load Groups that Aurora has adopted for its pricing methodology.

### 4.5.1 Load Groups

Aurora has selected load groups on the basis of physically distinguishable service delivery characteristics. As detailed below, these distinguishable characteristics mean that the shared network assets (i.e. asset classes) are utilised differently by each load group. The load groups are as follows:

Street Lighting	Public street lighting with a defined load pattern that share LV asset costs.
Load Group 0	Unmetered connections less than 1 kVA with defined load pattern (subset of load group L1).
Load Group 1	Single phase 60 amp capacity connections or less that share LV asset costs.
Load Group 2	All remaining connections that share LV asset costs.
Load Group 3	Three phase connections that may share some LV asset costs.
Load Group 3A	Three phase connections generally supplied direct from distribution transformer (subset of load group 3).
Load Group 4	Three phase connections supplied direct from distribution transformer – transformer may be owned by consumer and connections share general HV asset costs.
Load Group 5	Three phase connections – generally HV consumers and have dedicated HV lines / cables to supply the connection.

#### 4.5.2 Dunedin Area Cost Allocations

Step 1: Allocate the (regional) revenue requirement to asset classes

Total Asset Costs by Asset Class	ORC \$	ORC %	Allocated Revenue
33kV lines	\$ 36.8 million	11%	\$ 1.957 million
Zone substations	\$ 80.8 million	24%	\$ 5.850 million
High voltage lines	\$ 74.5 million	22%	\$ 7.065 million
Distribution substations	\$ 68.4 million	20%	\$ 6.145 million
Low voltage lines	\$ 81.4 million	24%	\$ 6.689 million
Total	\$341.8 million	100%	\$27.706 million

Table 6 - Dunedin pricing area distribution costs by asset

Step 2: Identify the extent to which each load group uses each asset class

The statistical parameters used for the allocation of area costs to load groups are as follows:

Group	kVA Range	Connections	Annual Energy Delivery (GWh)	Group Anytime Demand (MW)	Sum of Installed Capacity (MVA)	Group Control Period Demand (MW)
S/L	0	2	7.3	1.7	11.7	1.1
L1	0 – 15	50,691	416.8	120.5	750.4	94.9
L2	16 – 149	3,017	138.2	27.9	151.8	25.4
L3	150 - 499	189	84.1	16.9	47.4	14.8
L4	500 – 2,499	76	109.8	29.5	57.7	17.7
L5	2,500+	8	56.8	15.1	31.6	8.8
Total		53,983	813.0	211.6	1,050.6	162.6

Table 7 - Dunedin pricing area cost allocation statistics

Step 3: Identify the cost of the service provided to each load group

The following tables provide the revenue requirement for each load group. It should be noted that:

- The W33 load group relates to distributed generation and the revenue requirement represents dedicated assets provided to generators.
- The asset class costs for distribution have been allocated to load groups on the basis of 50% Group Anytime Demand and 50% Group Control Period Demand.
- The transmission interconnection component of pass-through costs (including the distributed generation allowance) has been allocated to load groups on the basis of Group Control Period Demand. The transmission connection charge component of pass-through costs has been allocated on the basis of Group Capacity.
- The balance of pass-through costs has been allocated to load groups on the basis of consumer numbers.

Cost Category	SL	L1	L2	L3	L4	L5	W33	Total
33kV lines	13	1,058	264	157	228	115	122	1,957
Zone substations	42	3,373	842	499	726	367		5,850
High voltage lines	54	4,281	1,068	633	923	106		7,065
Distribution substations	94	4,321	1,086	644				6,145
Low voltage lines	66	5,249	1,307	67				6,689
Total	270	18,281	4,567	2,001	1,877	588	122	27,706

Table 8 - Dunedin pricing area load group allocation of distribution costs

Cost Category	SL	L1	L2	L3	L4	L5	W33	Total
Pass-through	133	12,380	3,045	1,749	2,204	1,101		20,612

Table 9 - Dunedin pricing area load group allocation of pass-through costs

#### 4.5.3 Central Area Clyde and Cromwell GXP Cost Allocations

Step 1: Allocate the (regional) revenue requirement to asset classes

Total Asset Costs by Asset Class	ORC \$	ORC %	Allocated Revenue
66kV and 33kV lines	\$30.1 million	12%	\$1.505 million
Zone substations	\$21.9 million	9%	\$2.299 million
High voltage lines	\$80.6 million	33%	\$8.427 million
Distribution substations	\$51.2 million	21%	\$3.311 million
Low voltage lines	\$58.2 million	24%	\$2.473 million
Total	\$242.0 million	100%	\$18.015 million

Table 10 - Clyde / Cromwell pricing area distribution costs by asset

Step 2: Identify the extent to which each load group uses each asset class

The statistical parameters used for the allocation of area costs to load groups are as follows:

Group	kVA Range	Connections	Annual Energy Delivery (GWh)	Group Anytime Demand (MW)	Sum of Installed Capacity (MVA)	Group Control Period Demand (MW)
S/L	0	5	1.8	0.4	2.8	0.3
L1	0 – 15	16,046	108.2	34.9	234.9	32.6
L2	16 – 149	1,533	63.9	9.9	78.3	9.0
L3	150 - 499	96	28.4	6.4	21.8	3.5
L4	500 – 2,499	16	21.7	5.1	11.5	2.9
L5	2,500+					
Total		17,696	223.9	56.6	349.3	48.3

Table 11 - Clyde / Cromwell pricing area cost allocation statistics

Step 3: Identify the cost of the service provided to each load group

The following tables provide the revenue requirement for each load group. It should be noted that:

- The P33 load group relates to distributed generation and the revenue requirement represents dedicated assets provided to generators.
- The asset class costs for distribution have been allocated to load groups on the basis of 50% Group Anytime Demand and 50% Group Control Period Demand.
- The transmission interconnection component of pass-through costs (including the distributed generation allowance) has been allocated to load groups on the basis of Group Control Period Demand. The transmission connection charge component of pass-through costs has been allocated on the basis of Group Capacity.
- The balance of pass-through costs have been allocated to load groups on the basis of consumer numbers.

Cost Category	SL	L1	L2	L3	L4	L5	P33	Total
66kV/33kV lines	7	701	196	101	81		420	1,505
Zone substations	14	1,485	415	213	172			2,299
High voltage lines	52	5,442	1,519	781	632			8,427
Distribution substations	37	2,296	645	333				3,311
Low voltage lines	18	1,861	520	74				2,473
Total	128	11,785	3,295	1,502	885		420	18,015

Table 12 - Clyde / Cromwell pricing area load group allocation of distribution costs

Cost Category	SL	L1	L2	L3	L4	L5	P33	Total
Pass-through	26	3,242	867	364	297			4,797

Table 13 - Clyde / Cromwell pricing area load group allocation of pass-through costs

#### 4.5.4 Frankton Area Cost Allocations

Step 1: Allocate the (regional) revenue requirement to asset classes

Total Asset Costs by Asset Class	ORC \$	ORC %	Allocated Revenue
33kV lines	\$9.0 million	7%	\$452 million
Zone substations	\$20.7 million	16%	\$1.909 million
High voltage lines	\$36.3 million	28%	\$3.944 million
Distribution substations	\$27.6 million	21%	\$1.791 million
Low voltage lines	\$38.4 million	29%	\$1.950 million
Total	\$132.1 million	100%	\$10.047 million

Table 14 - Frankton pricing area distribution costs by asset

Step 2: Identify the extent to which each load group uses each asset class

The statistical parameters used for the allocation of area costs to load groups are as follows:

Group	kVA Range	Connections	Annual Energy Delivery (GWh)	Group Anytime Demand (MW)	Sum of Installed Capacity (MVA)	Group Control Period Demand (MW)
S/L	0	3	1.1	0.2	1.7	0.2
L1	0 – 15	10,751	93.6	30.5	156.6	30.2
L2	16 – 149	1,360	59.8	11.9	65.1	10.9
L3	150 - 499	63	22.0	6.3	15.8	4.2
L4	500 – 2,499	21	32.8	6.8	15.5	6.2
L5	2,500+	1	5.9	2.0	5.0	1.8
Total		17,696	223.9	57.8	259.6	53.4

Table 15 - Frankton pricing area cost allocation statistics

Step 3: Identify the cost of the service provided to each load group

The following tables provide the revenue requirement for each load group. It should be noted that:

- The P33 load group relates to distributed generation and the revenue requirement represents dedicated assets provided to generators.
- The asset class costs for distribution have been allocated to load groups on the basis of 50% Group Anytime Demand and 50% Group Control Period Demand.
- The transmission interconnection component of pass-through costs (including the distributed generation allowance) has been allocated to load groups on the basis of Group Control Period Demand. The transmission connection charge component of pass-through costs has been allocated on the basis of Group Capacity.
- The balance of pass-through costs has been allocated to load groups on the basis of consumer numbers.



<b>Cost Category</b>	<b>SL</b>	<b>L1</b>	<b>L2</b>	<b>L3</b>	<b>L4</b>	<b>L5</b>	<b>P33</b>	<b>Total</b>
33kV lines	2	226	85	39	48	14	38	452
Zone substations	7	1,043	391	180	223	65		1,909
High voltage lines	15	2,220	832	383	475	19		3,944
Distribution substations	18	1,142	432	199				1,791
Low voltage lines	9	1,369	514	59				1,950
<b>Total</b>	<b>51</b>	<b>6,001</b>	<b>2,253</b>	<b>859</b>	<b>746</b>	<b>98</b>	<b>38</b>	<b>10,047</b>

*Table 16 - Frankton pricing area load group allocation of distribution costs*

<b>Cost Category</b>	<b>SL</b>	<b>L1</b>	<b>L2</b>	<b>L3</b>	<b>L4</b>	<b>L5</b>	<b>P33</b>	<b>Total</b>
Pass-through	22	3,642	1,303	557	728	212		6,465

*Table 17 - Frankton pricing area load group allocation of pass-through costs*

## 5 Pricing Components

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### 5.1 Distribution Cost Recovery Components

#### 5.1.1 Standard Domestic Connections

A "Standard Domestic" connection is one where the connection capacity is set according to the size of network fuse provided for the short-circuit protection of consumers' mains. The default for a Standard Domestic connection is a single phase 60 amp fuse providing a connection capacity of up to 15kVA. A "low capacity" option is available, and is set by a single phase 32 amp fuse providing a connection capacity of up to 8kVA.

In order to be eligible for Standard Domestic pricing, premises must comply with the definition of "home" given in the Electricity (Low Fixed Charge Option for Domestic Consumers) Regulations 2004.

A domestic consumer's "home" is their principal place of residence and, for the avoidance of doubt, excludes holiday homes. Also excluded are:

- a) penal institutions;
- b) hospitals, homes or other institutions for care of sick, aged or disabled;
- c) police barracks, cells and lock-ups;
- d) armed forces barracks;
- e) hostel, dormitory or similar accommodation;
- f) premises occupied by a club for provision of temporary accommodation;
- g) hotels, motels, boarding houses; and
- h) camping grounds, motor camps or marinas.

If there is a likelihood of injection of energy from the connection, then two-way import/ export metering must be installed to remain on the Standard Domestic variable tariff.

Two components of line charges are used and the pricing details are outlined in Schedules 1 to 4 (A1, B1, C1, D1, E1). The components are as follows:

##### 5.1.1.1 Fixed Component

The fixed component has been set at 15 cents/day, which is the maximum fixed charge permitted under the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.

##### 5.1.1.2 Variable Components

The variable components are defined by the existing metering arrangements for each network area.

In the Dunedin area, most domestic connections have a single meter, which records general purpose and controlled water heating (minimum 16 hours service) consumption.

In the Central and Te Anau areas, most domestic connections have two meters – one to record general purpose consumption and one to record controlled water heating (minimum 16 hours service) consumption.

In both areas, the charges for controlled loads are discounted to reflect the lower contribution to peak loads by these loads.

### **5.1.2 Other Connections (Non-Domestic Connections and Non-Standard Domestic Connections including street lighting)**

Five components of line charges are used and the pricing details are outlined in Schedules 1 to 4 (A2, A3, B2, B3, C2, C3, D2, D3, E2, E3). The components are as follows:

#### **5.1.2.1 Fixed Charge**

This charge recovers costs that are incurred on a connection basis.

#### **5.1.2.2 Assessed Capacity Charge**

- **LV Metered Connections**

This charge recovers costs associated with the distribution system local to each connection point, i.e. LV lines and cables, distribution substations, and HV lines and cables. The use of these assets is more directly related to the capacity of the individual connections.

The basis for the annual Assessed Capacity is the minimum fuse size, mains size or standard distribution transformer size required to supply the maximum anytime power demand. Normally this will be the minimum fuse size for capacity up to 276 kVA and installed distribution capacity for capacity greater than or equal to 300 kVA. A further explanation of connection capacities is given in Aurora's Network Connection Requirements, available from [www.auroraenergy.co.nz](http://www.auroraenergy.co.nz).

- **HV Metered Connections**

This charge recovers costs associated with the distribution system local to each connection point, i.e. HV lines and cables. The use of these assets is more directly related to the capacity of the individual connections.

The basis for the annual Assessed Capacity of HV metered connections, excluding residential secondary networks which are assessed on the basis of installed distribution transformer capacity, is the lesser of the installed distribution transformer capacity (kVA) and minimum standard transformer capacity greater than 1.18 times the average of the 12 highest anytime power demands (kVA). The factor of 1.18 is used so that the average ratio of maximum anytime power demand (kVA) to Assessed Capacity (kVA) for HV metered connections is the same as for LV metered connections in Load Groups 4 and 5. See also section 4.1.

#### **5.1.2.3 kVA-km Charge**

For the L3, L3A, L4 and L5 load groups (assessed capacity 150 kVA or greater) the costs associated with HV lines and cables and subtransmission lines and cables are recovered by a kVA-km charge. The total kVA-km for each connection is the product of the connection capacity in kVA and the circuit distance from the distribution substation supplying the connection to the Aurora zone substation and then to the nearest Transpower supply point.

This charge recognises that additional investment in lines and cables is required to supply network connections that are a long way from Transpower supply points compared to those that are close to a Transpower supply point. At more remote locations, alternatives to electricity may be more appropriate and this component signals this fact.

#### **5.1.2.4 Control Period Demand Charge**

This charge recovers costs associated with zone substations and subtransmission lines and cables, which are sized for system peak loads.

The basis for the Control Period Demand (CPD kW) is the energy used at the installation when Aurora is managing demand. This energy usage will accumulate and at the end of the Control Period the accumulated energy is divided by the duration of the Control Period to obtain average power demand. If a consumer commences during the year a negotiated Control Period Demand will apply until a full winter is completed.

The Control Period Demand for each installation is set at 1 December to the average of CPD kW (Previous Winter) and chargeable CPD kW (at 1 December previous year). The Control Period is likely to occur on cold winter days, anytime between 7.30 am and 10.00 pm, and to last typically for two to three hours (but could last for up to ten hours on occasions) and is most likely to occur on approximately 20 to 50 days during the May to September period with most activity during June, July and August. Control periods will be signalled via ripple control and Consumers may use this signal, via clean relay contacts, to operate a warning device to directly control deferrable load or to start up a standby generator, whichever is the most convenient.

Where it is not presently economic to install Control Period Demand metering for connections such as Load Group 1 and 2, then any charges that would normally be recovered via a Control Period Demand charge will be recovered via an Effective Control Period Demand charge based upon kWh consumption at the installation during Winter days (0700 hours - 2300 hours). This will be based upon the four months consumption reported by electricity retailers for the period May to August. Energy consumed by defined night loads is discounted by 100%. A list of discount rates for kWh usage on controlled rate registers is set out in Schedule 6.

The Effective Control Period Demand for each installation is set at 1 December to the average of CPD kW (Previous Winter) and chargeable CPD kW (at 1 December previous year). Thus a strong economic signal exists for consumers to accept controlled loads.

By signalling the impact of network coincident demand in this way, Aurora is able to defer the need for investment in more capacity, which is a very expensive alternative. Consumers do not have to respond every time the signal is sent. Many will respond only when it suits, however the rewards for responding are substantial.

#### *5.1.2.5 Equipment Charge*

This charge recovers costs associated with distribution substations, including related switchgear, for the load groups 500 to 2499 kVA and 2500+ kVA where the consumer has opted not to own their own transformers or switchgear. This is consistent with Aurora charging for connection services on a shallow basis.

## **5.2 Pass-through Cost Recovery Components**

### **5.2.1 Standard Domestic Supply**

For Standard Domestic connections in load groups L1A ( $\leq 8$  kVA) and L1 ( $\leq 15$  kVA) the charges are recovered by a variable cents/kWh charge.

For the other L1A ( $\leq 8$  kVA), L1 ( $\leq 15$  kVA), L2 (16-149 kVA), L3 (150-249 kVA), L3A (250-499 kVA), L4 (500-2499 kVA) and L5 (2500+ kVA) load groups, all allocated pass-through costs excluding the transmission interconnection charge and distributed generation allowance are recovered by way of a charge per installed kVA capacity. Allocated transmission interconnection charges and the allocated distributed generation allowance are recovered by way of a charge per control period demand kW.

### 5.2.2 Loss and Constraint Rental Rebates

Loss and Constraint Rental Rebates are credits rebated by Transpower as a result of money received from the Clearing Manager for the Wholesale Electricity Market and are excluded from transmission charges. The rebates are allocated each month to Retailers on the basis of each retailer's total pass-through charges for the month in which the rebate applied. This credit is currently available in say mid-June for the month of April.

It would be preferable to allocate Loss and Constraint Rental Rebates on the basis of each retailer's total CPD (\$/kW) charges, since the rebates are generally a function of interconnection assets, and the total pass-through charges to each retailer incorporate recovery of some non-transmission related expenses. However, with a large proportion of pass-through recoveries occurring from Standard Domestic connections (approximately 54%) using a single variable charge, a more precise isolation of attributable charges is not currently possible. With transmission interconnection charges and the distributed generation allowance comprising approximately 79% of the total pass-through recovery, Aurora considers that the benefit of greater precision is not likely to be high.

### 5.3 Target Revenue by Price Component

Table 18, below, describes the allocation of target revenue to the price components described above.

	Price Component	Dunedin	Clyde and Cromwell	Frankton	Heritage Estate	Total
Distribution (\$'000's)	Fixed	\$2,857	\$987	\$802	\$6	\$4,452
	Variable	\$14,338	\$9,539	\$4,951	\$60	\$28,888
	Capacity	\$4,920	\$3,480	\$2,275	\$1	\$10,676
	kVA-km	\$227	\$433	\$111		\$771
	CPD	\$4,912	\$3,017	\$1,821	\$0	\$9,750
	Equipment	\$60	\$17			\$77
	Street lighting	\$270	\$122	\$48	\$3	\$443
	Generation	\$122	\$420	\$38		\$542
	<i>Subtotal</i>	<i>\$27,706</i>	<i>\$18,015</i>	<i>\$10,047</i>	<i>\$70</i>	<i>\$55,839</i>
Pass-through (\$'000's)	Fixed	\$37	\$47	\$225		\$309
	Variable	\$11,167	\$2,810	\$3,153		\$17,130
	Capacity	\$1,860	\$154	\$810		\$2,824
	CPD	\$7,416	\$1,758	\$2,255		\$11,429
	Street lighting	\$133	\$26	\$21		\$180
	<i>Subtotal</i>	<i>\$20,612</i>	<i>\$4,796</i>	<i>\$6,465</i>		<i>\$31,871</i>
Total		\$48,319	\$22,811	\$16,512	\$70	\$87,711

Table 18 - Target Revenue by Price Component

## 6 Seasonal Loads

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### 6.1 Background

Aurora has a large number of seasonal loads connected to its network such as irrigation pumps, general pumps and fruit packing houses. Some connections, such as irrigation pumps, have been disconnected to avoid line charges over the winter period.

Aurora has considered the option of having seasonal tariffs. However, in the interests of maintaining as few tariffs as possible to provide sufficient cost reflectivity (i.e. consistent with the Pricing Principles), Aurora has determined the following policy with respect to seasonal loads.

### 6.2 Line Pricing Recovery

Aurora's use-of-system charges are based on recovery by equal monthly instalments of an annual charge, which is adjusted after each network control period to reflect prior-winter peak period usage. Deliberate disconnection for part of a year to avoid part year charges is unacceptable.

### 6.3 Policy

For seasonal loads with capacity greater than 15kVA and advised to retailers, the following applies:

Any advice of a reconnection of a seasonal load that was disconnected within the previous 12 months will result in a Reconnection Charge equal to the monthly line charges not paid during the disconnected period, unless a written explanation satisfactory to Aurora is received.

Where disconnections occur for more than 12 months then Aurora reserves the right to remove assets dedicated to supply the de-energised ICPs and decommission the connection. Any request for subsequent reinstatement will be treated as if an application for a new connection was being made.

The Reconnection Charge will be invoiced to the retailer who requests the re-energising and it is possible that the retailer will be back billed for up to 12 months of line charges. It is essential that new retailers accepting switches check whether the ICP has been de-energised on the Registry and if it is a seasonal load.



## 7 Other Pricing Considerations

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Other considerations relevant to Aurora's pricing methodology are:

- (a) Charges apply per Installation Control Point (ICP).
- (b) Rural or remote rural loads are so few in number in comparison with those supplied by the meshed network that they have been included in the meshed network.
- (c) Charges for load group 4 (500 to 2499 kVA) and load group 5 (2500+ kVA) have been calculated on the basis that they are all HV metered installations; an additional charge will apply where Aurora owns the transformers and associated HV switchgear.
- (d) Charges do not include energy losses on the distribution network. Energy retailers must purchase their share of system losses using the loss factors as published on Aurora's website [www.auroraenergy.co.nz](http://www.auroraenergy.co.nz).
- (e) Charges exclude metering services involved with the provision of meters or meter reading. These services are provided by others.
- (f) The amounts budgeted for asset maintenance are detailed in Aurora's Asset Management Plan under the following categories:
  - system control
  - subtransmission lines and cables (66kV & 33 kV)
  - zone substations (33 kV to 11 kV and 6.6 kV transformation)
  - HV lines and cables (11 kV and 6.6 kV)
  - distribution substations (11/6.6 kV to 400 V transformation)
  - LV lines and cables (400 V).

The asset maintenance programme is determined by; safety requirements, reliability objectives, and repairs to equipment following faults. The safety and reliability requirements set the planned programme for maintenance as detailed in the Asset Management Plan.

- (g) Use of the above assets by each load group determines the total cost to be recovered from each load group.

## 8 Non-standard Contracts

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Aurora may consider entering into a non-standard contract with consumers where there are sufficiently compelling reasons to do so. Broadly, a consumer should meet some or all of the following criteria in order for a non-standards contract to be considered:

- The Assessed Capacity of the Consumer's connections exceeds 1,000kVA
- The Consumer's connection is dedicated
- The Consumer's load profile is significantly different from comparable connections
- The Consumer can clearly demonstrate that continuation of standards arrangements is likely to result in inefficient outcomes.

Aurora has three operative non-standard agreements, covering 9 ICPs. Aurora expects to generate approximately 0.44% of target revenue (\$389,088) from these ICPs in the year to 31 March 2016.

## 9 Distributed Generation

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This section outlines the methodology by which charges associated with the connection of distributed generation are calculated.

This methodology applies to distributed generation connected at high voltage only, and generally does not apply to generation connected behind load. In these cases, normal line charges apply according to the installation connection capacity.

### 9.1 General

There are three types of financial transactions that may apply when Distributed Generation is connected to the Aurora network. The transactions are:

- (a) connection charges paid by the Distributed Generator to Aurora;
- (b) recovery of HVDC Transmission Charges paid by the Distributed Generator to Aurora; and
- (c) avoided Transmission Charges<sup>16</sup> paid by Aurora to the Distributed Generator.

These are normally only applicable to large capacity generation. Generators must be pre-approved and able to demonstrate reliable and significant injection, particularly where the distributed generation is behind load.

Small-scale distributed generation does not require any specific attention. Because this generation sits behind load, normal line charges apply according to the installation's connection capacity. Owners of small-scale distributed generation that forms part of a standard domestic connection are able to avoid the full retail costs of energy (per unit), including the line charge component.

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<sup>16</sup> Referred to in sections 1 to 8 as the Distributed Generation Allowance in accordance with regulatory terminology; however, in this section we have maintained the term Avoided Transmission as this more accurately conveys the basis of the charge to interested persons.

The degree to which owners of small-scale distributed generation forming part of a non-domestic connection received benefits depends largely on the electricity retailer's offering; however, from Aurora's perspective, these consumers are able to avoid a significant proportion of the distribution and pass-through CPD price components.

## 9.2 Distributed Generation Connection Charge

The Distributed Generation connection charge recovers costs associated with assets provided by Aurora in the following situations:

- a) Assets provided solely for the connection of the distributed generation to the distribution network
- b) Use of shared assets that are required due to the capacity required by the Distributed Generator and which are in excess of that required for the local network.

The charge comprises three components:

- A return on investment; and
- Depreciation; and
- Maintenance costs.

### 9.2.1 Return on Investment (ROI)

Aurora will value the assets used exclusively for conveying electricity produced by Distributed Generators at Depreciated Replacement Cost (DRC) and apply a pre-tax Weighted Average Cost of Capital (WACC). The bulk of qualifying assets are likely to be overhead lines and cables; however, circuit breakers, instrument transformers, switches, protection and SCADA assets may also be involved.

In most circumstances, the Distributed Generator's electricity will be injected into Aurora's subtransmission network (33kV and 66kV); however injection into Aurora's 11kV distribution network may be possible.

Where generation specific subtransmission circuits and lower voltage distribution circuits share the same structures, the value of the assets attributable to the Distributed Generator will be the DRC value of the subtransmission circuit, less the difference between the calculated DRC of a stand-alone distribution circuit that would have been built had the distributed generation (and hence the subtransmission circuit) not existed, and the DRC of the existing under-built circuit.

Where multiple Distributed Generators share assets that Aurora has provided exclusively for conveying electricity produced by Distributed Generators, the return on investment component will be apportioned according to the ratio of the nameplate rating of the Distributed Generator's plant to the sum of the total nameplate rating of all the Distributed Generators' plant utilising those shared assets.

Aurora will provide an asset valuation table and, where multiple Distributed Generators are involved, apportionment calculations as part of its contract with the Distributed Generator.

### 9.2.2 Depreciation

Aurora will value the assets used exclusively for conveying electricity produced by Distributed Generators at Replacement Cost (RC). Depreciation will be calculated according to the standard lives for each appropriate asset class<sup>17</sup>. Accordingly, the calculation will be:

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<sup>17</sup> In the case of subtransmission lines, Aurora may use a reasonable estimate of the proportion of pole types (concrete or wood) to calculate a composite asset life.

$$\text{Depreciation Charge (\$)} = \sum (\text{RC}_{(\text{class})} (\$)) \times \frac{1}{\text{Standard Life}_{(\text{class})} (\text{years})}$$

Where multiple Distributed Generators share assets that Aurora has provided exclusively for conveying electricity produced by Distributed Generators, the depreciation component will be apportioned according to the ratio of the nameplate rating of the Distributed Generator's plant to the sum of the total nameplate rating of all Distributed Generators' plant utilising those shared assets.

Aurora will provide an asset valuation table, table of depreciation charges and, where multiple Distributed Generators are involved, apportionment calculations, as part of its contract with the Distributed Generator.

### 9.2.3 Maintenance

Budgets are set annually for the maintenance of all Aurora assets.

The maintenance component attributable to Distributed Generators will be the ratio of the Replacement Cost (RC) of assets that Aurora has provided exclusively for conveying electricity produced by the Distributed Generator, to the RC of all assets of the same class in the same area.

Example:

*Aurora provides subtransmission lines with an RC of \$1.5 million, and 33kV zone substation equipment with an RC of \$0.8 million, in order to maintain a point of injection for a Distributed Generator operating in Central Otago. In Central Otago, the RC of all subtransmission assets is \$20 million, and all zone substation equipment is \$27 million. Maintenance of Central Otago subtransmission equipment is budgeted at \$350,000, and zone substation equipment at \$300,000.*

*The maintenance component of the Distribution Charge attributable to the Distributed Generation is:*

$$\frac{(\$1,500,000 + \$800,000)}{(\$20,000,000 + \$27,000,000)} \times (\$350,000 + \$300,000) = \$31,808$$

Where multiple Distributed Generators share assets that Aurora has provided exclusively for conveying electricity produced by Distributed Generators, the maintenance component will be apportioned according to the ratio of the nameplate rating of the Distributed Generator's plant to the sum of the total nameplate rating of all Distributed Generators' plant utilising those shared assets.

Aurora will provide an asset valuation table, table of budgeted maintenance costs and, where multiple Distributed Generators are involved, apportionment calculations, as part of its contract with the Distributed Generator.

### 9.2.4 New Generation

Where a new Distributed Generator proposes to connect to shared assets that Aurora has provided exclusively for conveying electricity produced by Distributed Generators, or an existing Distributed Generator proposes to increase the amount of generation injected into the Aurora network, additional assets or network reinforcement may be required to accommodate transmission of the new or increased generation and maintain the transmission capability allocated to existing Distributed Generators. In such circumstances, ROI, depreciation and maintenance charges associated with the additional assets or network reinforcement shall be attributed to the Distributed Generator requiring the additional investment.

## 9.3 Connection Charge Adjustments

### 9.3.1 Inflation Adjustment

The Distributed Generation connection charge will be adjusted annually for increases in inflation. The adjustment is based on the annual increase in the Consumers Price Index for the September quarter, and the adjusted connection charge will take effect from 1 April.

### 9.3.2 5-yearly Valuation Review

Distributed Generation connection charges will be adjusted every five years for any change in the asset values that underpin the connection charge, which may have occurred as a result of asset renewals and replacements.

## 9.4 Transmission Related Transactions

### 9.4.1 Avoided Transmission (Interconnection) Payments

Distributed Generation reduces Aurora's off-take requirements at Grid Exit Points (GXPs). If the distributed generation occurs during the periods which Transpower uses to base its charges to Aurora under its connection contracts, then the transmission charges paid by Aurora to Transpower will be less. The key transmission charge component that is reduced in practice is the Interconnection Charge. Based upon the current EA Transmission Pricing Methodology (TPM) the following applies and is subject to change if the TPM changes.

Aurora will pay Distributed Generators a proportion of the avoided Interconnection Charges created by their injection into Aurora's network. The amount retained by Aurora recognises that there are significant administration and data management costs associated with Distributed Generation connections. The proportions paid are listed below:

Generation Capacity	Avoided Transmission Rate (ATR)
5MW and above	95%
Between 500kW and 5 MW*	90%
Below 500kW	0%

\* Distributed Generators within this band must be pre-approved and able to demonstrate reliable and significant injection, particularly where the distributed generation is behind load. Half-hourly metering is a prerequisite.

Table 19 - Avoided transmission rate by generation capacity

Transpower sets its Interconnection Charge, for each GXP serving the Aurora network, by multiplying its national Interconnection Rate (IR) \$ per kW, by the average off-take demand occurring at the GXP during the same dates and times of the highest 100 demand peaks occurring in the Lower South Island during the period 1 September to 31 August (Transpower Capacity Measurement Period). The Interconnection Charge then applies during the following 1 April to 31 March period.

Aurora calculates a Without Generation Interconnection Demand based on the average system demand at each GXP of the Aurora network during dates and times of the highest 100 demand peaks occurring in the Lower South Island.

The difference between the calculated Without Generation Interconnection Demand and Transpower's Interconnection Demand is the Avoided Transmission Demand for that GXP, and gives rise to the Avoided Transmission Charge (AVC) payable by Aurora to Distributed Generators.

Where there are multiple Distributed Generators operating in a GXP, then the Avoided Transmission Demand needs to be shared between Distributed Generators. The Avoided Transmission Demand will be allocated to each Distributed Generator based upon the ratio of their average generation (MW) to the total average distributed generation (MW) during the same dates and times that the Transpower Interconnection Demands occur.

The AVC paid to each Distributed Generator is based upon:

$$AVC_{(Gen)} = \frac{\text{Avoided Demand}^*}{\text{Transmission}} \times ATR \times IC$$

where:

ATR is the Avoided Transmission Rate according to Table 1.

IC is the Interconnection Rate set annually by Transpower.

Since Avoided Transmission Charges are based on historical data, Distributed Generators may not become eligible for avoided transmission payments until they have recorded injection into the Aurora network during the highest 100 demand peaks occurring in the Lower South Island during the period 1 September to 31 August. Once qualifying, Avoided Transmission Payments will be made to the Distributed Generator from the following April.

#### 9.4.2 Recovery of HVDC Charges

Where net injection to the Grid occurs at a GXP serving the Aurora network, Aurora will incur HVDC Charges from Transpower. These charges are designed to recover Transpower's revenue requirements for operating the HVDC link between Benmore in the South Island, and Haywards in the North Island. Aurora will recover the HVDC Charges from the Distributed Generators that cause the charges to occur.

Transpower sets its HVDC Charges, for each GXP serving the Aurora network, by multiplying its HVDC Rate (DCR) by the Historic Anytime Maximum Injection (HAMI) recorded at the GXP. HAMI is defined as the higher of:

- a) The average of the 12 highest injections recorded at the GXP during the period 1 September to 31 August for the following pricing year, or
- b) The average of the 12 highest injections recorded at the GXP during any of the four immediately preceding pricing years.

Accordingly, Distributed Generators are only liable for HVDC Charges if operating during at least one of the 12 injection peaks that comprise the HAMI for the current pricing year. Because Transpower's method essentially looks at the highest maximum injection in the past five years, a new Distributed Generator may not become liable for HVDC Charges for several years.

The proportion of the HVDC Charge attributable to any Distributed Generator is that Generator's average injection into the Aurora network (within the GXP area) during the designated 12 HAMI peaks, divided by the total generation injection into the Aurora network (within the GXP area) during the designated 12 HAMI peaks.

## 10 Glossary

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CPD	control period demand
CPI	consumers' price index
CPI-X	price regulation methodology set by Commerce Commission
EA	Electricity Authority
EDB	Electricity Distribution Business
GWh	gigawatt hours
GXP	grid exit point
HV	high voltage
HVDC	high voltage direct current
km	kilometre
kVA	kilovolt ampere
kW	kilowatt
kWh	kilowatt hour
ICP	installation control point
LV	low voltage
MVA	megavolt ampere
MW	megawatt
ODRC	optimised depreciated replacement cost
ORC	optimised replacement cost
SSDG	small-scale distributed generation
TPM	transmission pricing methodology

## Schedule A – Prices – South Dunedin & Halfway Bush GXPs

Effective: 1 April 2015

A.1 – STANDARD DOMESTIC CONNECTIONS		Registry Code	Per Annum	
			Distribution	Pass-through
Fixed Annual Charge (≤15 kVA)		SHSD15	\$54.73	
Fixed Annual Charge (≤8 kVA) (note 6)		SHSD8	\$15.00	
Uncontrolled Variable Charges		Tariff Code	(¢ / kWh)	
General Purpose	All day Summer	010	5.89	2.30
General Purpose	All day Winter	010	6.58	5.68
Controlled Variable Charges		Tariff Code	(¢ / kWh)	
General Purpose + 16 hour water heat	All day Summer	017	2.87	2.23
General Purpose + 16 hour water heat	All day Winter	017	4.25	3.39
Night + 3 hours		024	1.49	0.73
Night rate		028	0.40	
Gen Purpose + 16 hour w/h – D/N	Summer Day	011	5.37	2.27
Gen Purpose + 16 hour w/h – D/N	Winter Day	011	5.62	5.88
Gen Purpose + 16 hour w/h – D/N	Summer Night	012	0.40	
Gen Purpose + 16 hour w/h – D/N	Winter Night	012	0.40	

A.2 – STREET LIGHTING & DISTRIBUTED UNMETERED LOAD (DUML)		Registry Code	Per Annum	
			Distribution	Pass-through
Fixed Annual Charge	0000201300DE692	SDNSTL	\$91,261	\$44,892
Fixed Annual Charge	0000203111DE930	HWBSTL	\$178,701	\$87,904
Fixed Annual Charge (DUML)		SHSUNM	\$13.56	
Variable Charge (DUML)		030	1.34	1.94

A.4 – OTHER CONNECTIONS				Per Annum			
Registry Code		Load Group	Capacity (kVA)	Fixed (\$)	Capacity (\$ / kVA)	kVA-km (\$ / kVA-km)	Control Period (\$ / kW)
Distribution	SH0	L0	0 - 1	\$110.30			
	SH0A	L0A (note 5)	0 - 2	\$228.99			
	SH1A	L1A (note 6)	0 - 8	\$10.25	\$14.19		\$88.50
	SH1	L1	0 - 15	\$10.25	\$12.70		\$88.50
	SH2	L2 (note 8)	16 - 149	\$22.09	\$14.85		\$88.50
	SH3	L3	150 - 249	\$402.00	\$23.65	\$0.28	\$53.10
	SH3A	L3A	250 - 499	\$402.00	\$21.75	\$0.28	\$53.10
	SH4	L4 (note 9)	500 - 2,499	\$1,012.00	\$12.95	\$0.28	\$51.00
	SH5	L5 (note 9)	2,500 +	\$1,012.00	\$7.39	\$0.28	\$32.00
Pass-through	SH0	L0	0 - 1	\$87.72			
	SH0A	L0A (note 5)	0 - 2	\$189.45			
	SH1A	L1A (note 6)	0 - 8		\$10.07		\$107.00
	SH1	L1	0 - 15		\$8.70		\$107.00
	SH2	L2	16 - 149		\$3.55		\$107.00
	SH3	L3	150 - 249		\$6.10		\$106.50
	SH3A	L3A	250 - 499		\$6.10		\$106.50
	SH4	L4	500 - 2,499		\$7.70		\$106.50
	SH5	L5	2,500 +		\$5.30		\$106.50



## Schedule B – Prices – Clyde & Cromwell GXPs

Effective: 1 April 2015

B.1 – STANDARD DOMESTIC CONNECTIONS		Registry Code	Per Annum	
			Distribution	Pass-through
Fixed Annual Charge ( $\leq 15$ kVA)		CCSD15	\$54.73	
Fixed Annual Charge ( $\leq 8$ kVA) (note 6)		CCSD8	\$15.00	
Uncontrolled Variable Charges		Tariff Code	(¢ / kWh)	
General Purpose	All day Summer	101	10.26	2.06
General Purpose	All day Winter	101	13.80	4.66
Controlled Variable Charges		Tariff Code	(¢ / kWh)	
Peak Water Heating	20 hour service	109	7.38	2.48
Standard Water Heating	16 hour service	106	5.34	1.46
Night + 5 Hours	13 hour service	103	6.01	2.10
Night + 3 Hours	11 hour service	104	4.92	1.11
Night		108	4.21	

B.2 – STREET LIGHTING	Registry / Tariff Code	(¢ / kWh)	
Fixed Annual Charge per lamp	CCSTL	\$13.56	
Variable Charge	110	4.08	1.44

B.3 – OTHER CONNECTIONS				Per Annum			
Registry Code		Load Group	Capacity (kVA)	Fixed (\$)	Capacity (\$ / kVA)	kVA-km (\$ / kVA-km)	Control Period (\$ / kW)
Distribution	CC0	L0	0 - 1	\$194.36			
	CC0A	L0A (note 5)	0 - 2	\$370.56			
	CC1A	L1A (note 6)	0 - 8	\$13.68	\$30.94		\$181.12
	CC1	L1	0 - 15	\$13.68	\$28.58		\$181.12
	CC2	L2 (note 8)	16 - 149	\$28.74	\$24.00		\$152.30
	CC3	L3	150 - 249	\$548.00	\$28.94	\$0.37	\$171.00
	CC3A	L3A	250 - 499	\$548.00	\$25.65	\$0.37	\$171.00
	CC4	L4 (note 9)	500 - 2,499	\$1,439.00	\$20.50	\$0.37	\$148.00
	CC5	L5 (note 9)	2,500 +	\$1,439.00	\$18.45	\$0.37	\$137.60
Pass-through	CC0	L0	0 - 1	\$64.94			
	CC0A	L0A (note 5)	0 - 2	\$163.43			
	CC1A	L1A (note 6)	0 - 8		\$3.49		\$99.00
	CC1	L1	0 - 15		\$2.30		\$99.00
	CC2	L2	16 - 149		\$0.55		\$90.20
	CC3	L3	150 - 249		\$0.98		\$97.00
	CC3A	L3A	250 - 499		\$0.98		\$97.00
	CC4	L4	500 - 2,499		\$1.80		\$97.00
	CC5	L5	2,500 +		\$1.80		\$97.00

## Schedule C – Prices – Frankton GXP

Effective: 1 April 2015

C.1 – STANDARD DOMESTIC CONNECTIONS		Registry Code	Per annum	
			Distribution	Pass-through
Fixed Annual Charge ( $\leq 15$ kVA)		FRSD15	\$54.73	
Fixed Annual Charge ( $\leq 8$ kVA) (note 6)		FRSD8	\$15.00	
Uncontrolled Variable Charges		Tariff Code	(\$ / kWh)	
General Purpose	All day Summer	201	7.04	2.64
General Purpose	All day Winter	201	8.66	5.86
Controlled Variable Charges		Tariff Code	(\$ / kWh)	
Peak Water Heating	20 hour service	209	4.07	2.53
Standard Water Heating	16 hour service	206	1.82	1.77
Night + 5 Hours	13 hour service	203	2.66	2.21
Night + 3 Hours	11 hour service	204	1.63	1.16
Night		208	1.17	

C.2 – STREET LIGHTING	Registry / Tariff Code	(¢ / kWh)	
Fixed Annual Charge per lamp	FRSTL	\$13.56	
Variable Charge	210	1.30	1.94

C.3 – OTHER CONNECTIONS				Per Annum			
Registry Code		Load Group	Capacity (kVA)	Fixed (\$)	Capacity (\$ / kVA)	kVA-km (\$ / kVA-km)	Control Period (\$ / kW)
Distribution	FR0	L0	0 - 1	\$127.40			
	FR0A	L0A (note 5)	0 - 2	\$230.82			
	FR1A	L1A (note 6)	0 - 8	\$11.99	\$17.29		\$81.39
	FR1	L1	0 - 15	\$11.99	\$16.20		\$81.39
	FR2	L2 (note 8)	16 - 149	\$19.49	\$18.82		\$94.50
	FR3	L3	150 - 249	\$442.00	\$37.20	\$0.35	\$59.90
	FR3A	L3A	250 - 499	\$442.00	\$34.07	\$0.35	\$59.90
	FR4	L4 (note 9)	500 - 2,499	\$1,165.00	\$22.02	\$0.35	\$61.69
	FR5	L5 (note 9)	2,500 +	\$1,165.00	\$1.43	\$0.35	\$42.42
Pass-through	FR0	L0	0 - 1	\$80.04			
	FR0A	L0A (note 5)	0 - 2	\$181.24			
	FR1A	L1A (note 6)	0 - 8		\$13.77		\$97.50
	FR1	L1	0 - 15		\$13.10		\$97.50
	FR2	L2	16 - 149		\$4.05		\$97.50
	FR3	L3	150 - 249		\$11.20		\$96.30
	FR3A	L3A	250 - 499		\$11.20		\$96.30
	FR4	L4	500 - 2,499		\$12.10		\$96.30
	FR5	L5	2,500 +		\$16.62		\$96.30

## Schedule D – Prices – Frankton GXP<sup>18</sup>

Effective: 1 April 2015

D.1 – STANDARD DOMESTIC CONNECTIONS		Registry Code	Per annum	
			Distribution	Pass-through
Fixed Annual Charge (≤15 kVA)		FKSD15	\$54.73	
Fixed Annual Charge (≤8 kVA) (note 6)		FKSD8	\$15.00	
Uncontrolled Variable Charges		Tariff Code	(¢ / kWh)	
General Purpose	All day Summer	301	7.04	2.64
General Purpose	All day Winter	301	8.66	5.86
Controlled Variable Charges		Tariff Code	(¢ / kWh)	
Peak Water Heating	20 hour service	309	4.07	2.53
Standard Water Heating	16 hour service	306	1.82	1.77
Night + 5 Hours	13 hour service	303	2.66	2.21
Night + 3 Hours	11 hour service	304	1.63	1.16
Night		308	1.17	

D.2 – STREET LIGHTING		Registry / Tariff Code	(¢ / kWh)	
Fixed Annual Charge per lamp		FKSTL	\$13.56	
Variable Charge		310	1.30	1.94

D.3 – OTHER CONNECTIONS				Per Annum			
Registry Code		Load Group	Capacity (kVA)	Fixed (\$)	Capacity (\$ / kVA)	kVA-km (\$ / kVA-km)	Control Period (\$ / kW)
Distribution	FK0	L0	0 - 1	\$127.40			
	FK0A	L0A (note 5)	0 - 2	\$230.82			
	FK1A	L1A (note 6)	0 - 8	\$11.99	\$17.29		\$81.39
	FK1	L1	0 - 15	\$11.99	\$16.20		\$81.39
	FK2	L2 (note 8)	16 - 149	\$17.54	\$16.93		\$85.05
	FK3	L3	150 - 249	\$365.00	\$30.69	\$0.35	\$49.42
	FK3A	L3A	250 - 499	\$365.00	\$28.11	\$0.35	\$49.42
	FK4	L4 (note 9)	500 - 2,499	\$903.00	\$17.06	\$0.35	\$47.81
	FK5	L5 (note 9)	2,500 +	\$903.00	\$1.11	\$0.35	\$32.88
Pass-through	FK0	L0	0 - 1	\$80.04			
	FK0A	L0A (note 5)	0 - 2	\$181.24			
	FK1A	L1A (note 6)	0 - 8		\$13.77		\$97.50
	FK1	L1	0 - 15		\$13.10		\$97.50
	FK2	L2	16 - 149		\$4.05		\$97.50
	FK3	L3	150 - 249		\$11.20		\$96.30
	FK3A	L3A	250 - 499		\$11.20		\$96.30
	FK4	L4	500 - 2,499		\$12.10		\$96.30
	FK5	L5	2,500 +		\$16.62		\$96.30

<sup>18</sup> Sub area – note 15

## Schedule E – Prices – Heritage Estate Subdivision (Te Anau)

(Note 12)

Effective: 1 June 2014

E.1 – STANDARD DOMESTIC CONNECTIONS		Registry Code	Per annum	
			Distribution	Transmission
Fixed Annual Charge ( $\leq 15$ kVA)		HESD15	\$54.73	
Fixed Annual Charge ( $\leq 8$ kVA) (note 6)		HESD8	\$15.00	
Uncontrolled Variable Charges		Tariff Code	(¢ / kWh)	
General Purpose	All day Summer	401	7.90	2.40
General Purpose	All day Winter	401	9.69	5.81
Controlled Variable Charges		Tariff Code	(¢ / kWh)	
Standard Water Heating	16 hour service	406	3.12	1.70
Night + 3 Hours	11 hour service	404	2.86	1.41
Night		408	2.85	

E.2 – STREET LIGHTING	Registry / Tariff Code	(¢ / kWh)	
Fixed Annual Charge per lamp	HESTL	\$13.56	
Variable Charge	410	4.67	2.01

E.3 – OTHER CONNECTIONS				Per Annum			
Registry Code		Load Group	Capacity (kVA)	Fixed (\$)	Capacity (\$ / kVA)	kVA-km (\$ / kVA-km)	Control Period (\$ / kW)
Distribution	HE0	L0	0 - 1	\$149.35			
	HE0A	L0A (note 5)	0 - 2	\$279.08			
	HE1A	L1A (note 6)	0 - 8	\$10.72	\$25.41		\$135.94
	HE1	L1	0 - 15	\$10.72	\$23.81		\$135.94
	HE2	L2 (note 8)	16 - 149	\$22.51	\$22.43		\$135.31
Transmission	HE0	L0	0 - 1	\$64.88			
	HE0A	L0A (note 5)	0 - 2	\$163.31			
	HE1A	L1A (note 6)	0 - 8		\$1.54		\$98.77
	HE1	L1	0 - 15		\$0.28		\$98.77
	HE2	L2	16 - 149		\$0.16		\$91.49

## Schedule F – Notes to Price Schedules

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1. All charges are exclusive of GST.
2. Variable charges apply to kWh as metered at each ICP. The hours of service for water heating loads are target minimum levels of service. In unusual network circumstances it may be necessary for the target level to be less.
3. Capacity provided is on the basis of LV fuse size or transformer capacity.
4. Load group L0 is for approved unmetered supplies only.
5. Load group L0A is for approved unmetered builders temporary supply with maximum capacity of 15 kVA and subject to special conditions.
6.  $\leq 8$  kVA connections require a sealed 32 Amp MCB installed on the meter board.
7. The summer period is 1 October to 30 April and winter is 1 May to 30 September.
8. For connections in LG2 and above that satisfy the criteria for domestic as defined in the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004, then Standard Domestic pricing is available as an option.
9. For L4 and L5 load groups an additional \$8.40 per kVA of capacity applies if Aurora owns the distribution transformer.
10. An additional \$85.20 per kVAr per annum of equivalent corrective capacitance applies if the installation power factor is required to be improved to 0.95.
11. Loss Rental Rebates are excluded from pass-through charges and are credited separately.
12. Heritage Estate is a small 180 lot subdivision in the Te Anau area.
13. The registry code of "NOCHARGE" applies to Aurora ICPs that do not incur any network charges.
14. For dual register meters that measure day and night consumption separately, day variable rates apply to consumption recorded between 7am and 11pm, and night variable rates apply to consumption recorded between 11pm and 7am.
15. The Frankton sub area is defined by Aurora as comprising connections at threat from uneconomic bypass as a result of competitive, grid-connected distribution services. A prudent discount policy applies.

## Schedule G – Register Discount Rates for Assessed CPD kW Calculation

The table below lists the discount rate to be applied to the winter kWh for each register prior to the calculation of the assessed CPD kW for each ICP. The network tariff codes contained in the table are those to be supplied for variable consumption reporting in retailer EIEP1 files submitted to Aurora.

Register Contents	Network Tariff Code Dunedin		Network Tariff Code Clyde/Cromwell		Network Tariff Code Frankton		Network Tariff Code Frankton sub area		Network Tariff Code Heritage Estate		CPD kW Discount
	Standard Domestic	Non- Standard Domestic	Standard Domestic	Non- Standard Domestic	Standard Domestic	Non- Standard Domestic	Standard Domestic	Non- Standard Domestic	Standard Domestic	Non- Standard Domestic	
IN19	017	017\$ND	-	-	-	-	-	-	-	-	42%
UN24	010	010\$ND	101	101\$ND	201	201\$ND	301	301\$ND	401	401\$ND	Nil
CN11	024	024\$ND	104	104\$ND	204	204\$ND	304	304\$ND	404	404\$ND	75%
CN8	028	028\$ND	108	108\$ND	208	208\$ND	308	308\$ND	408	408\$ND	100%
IN16	011	011\$ND	-	-	-	-	-	-	-	-	20%
IN8	012	012\$ND	-	-	-	-	-	-	-	-	100%
CN20	-	-	109	109\$ND	209	209\$ND	309	309\$ND	-	-	25%
CN16	006	006\$ND	106	106\$ND	206	206\$ND	306	306\$ND	406	406\$ND	50%
CN13	-	-	103	103\$ND	203	203\$ND	303	303\$ND	-	-	60%
CN10	-	-	145	145\$ND	245	245\$ND	345	345\$ND	-	-	100%
DC16	013	013\$ND	-	-	-	-	-	-	-	-	50%
NC8	014	014\$ND	-	-	-	-	-	-	-	-	100%
D16	015	015\$ND	115	115\$ND	215	215\$ND	315	315\$ND	415	415\$ND	Nil
N8	016	016\$ND	116	116\$ND	216	216\$ND	316	316\$ND	416	416\$ND	100%
EG24 (Distributed Generation)	090	090\$ND	190	190\$ND	290	290\$ND	390	390\$ND	490	490\$ND	Nil

## Schedule H – Compliance Matrix

This schedule demonstrates how this Use-of-System Pricing Methodology complies with the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 (Decision No. NZCC22).

Information Disclosure Requirement	Determination Reference	Price Methodology Reference
Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which Explains whether, and if so how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.	Clause 2.4.1 (4)	Section 2.2
Every disclosure under clause 2.4.1 above must:		
Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group	Clause 2.4.3 (1)	Section 5
Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles	Clause 2.4.3 (2)	Sections 2.4 to 2.6
State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies	Clause 2.4.3 (3)	Section 4.4
Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components	Clause 2.4.3 (4)	Section 4.4
State the consumer groups for whom prices have been set, and describe- (a) the rationale for grouping consumers in this way; (b) the method and the criteria used by the EDB to allocate consumers to each of the consumer groups	Clause 2.4.3 (5)	Sections 3.1.4 & 4.5
If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons	Clause 2.4.3 (6)	Section 4.4.1

Information Disclosure Requirement	Determination Reference	Price Methodology Reference
Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way	Clause 2.4.3 (7)	Section 4.5
State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	Clause 2.4.3 (8)	Section 5.3
Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy:		
Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set	Clause 2.4.4 (1)	Section 3.2
Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy	Clause 2.4.4 (2)	Section 3.2
If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes	Clause 2.4.4 (3)	Section 3.2
Every disclosure under clause 2.4.1 above must describe the approach to setting prices for non-standard contracts, including:		
the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts	Clause 2.4.5 (1) (a)	Section 8
how the EDB determines whether to use a non-standard contract, including any criteria used	Clause 2.4.5 (1) (b)	Section 8
any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles	Clause 2.4.5 (1) (c)	Section 8
Every disclosure under clause 2.4.1 above must describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain:		
the extent of the differences in the relevant terms between standard contracts and non-standard contracts	Clause 2.4.5 (2) (a)	Section 8
any implications of this approach for determining prices for consumers subject to non-standard contracts	Clause 2.4.5 (2) (b)	Section 8



Information Disclosure Requirement	Determination Reference	Price Methodology Reference
Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the prices; and value, structure and rationale for any payments to the owner of the distributed generation.	Clause 2.4.5 (3)	Section 9.2
	Clause 2.4.5 (3) (a)	Schedules A & B
	Clause 2.4.5 (3) (b)	Section 9.4