
Use-of-System Pricing Methodology

Effective: 1 April 2013

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1 CHANGES TO PRICING METHODOLOGY

There has been no material change to Aurora's pricing methodology since the methodology was last published in April 2012. A potential change to the timeframe in which reviewed congestion period demands are applied is signalled in section 5.1.2.4.

The Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 (Decision No. NZCC22) specifies a number of new matters that must be addressed in EDBs' pricing methodologies. New items required to be disclosed under the Determination are:

- a) disclosure of pricing strategy;
- b) disclosure of the development of prices for non-standard contracts; and
- c) disclosure of the development of prices for distributed generation connections.

2 INTRODUCTION

As a supplier of an essential service, Aurora Energy Limited (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 perceive price as being more important than quality, however there may be a decreasing trend in this with it being of less importance in 2012 than 2011. This observation also aligns with the results from the mail survey.
- An increasing number of consumers are generally less willing to pay more for improvements in quality (reliability), but at the same time also don't want to pay less if it means there may be more interruptions.
- Results over time have shown that the 'number of interruptions' is perceived as the most important issue overall. However, this appears to be becoming less of an issue overall in terms of it being the 'single most important' to consumers compared to length of interruptions and voltage fluctuations.

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.

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.

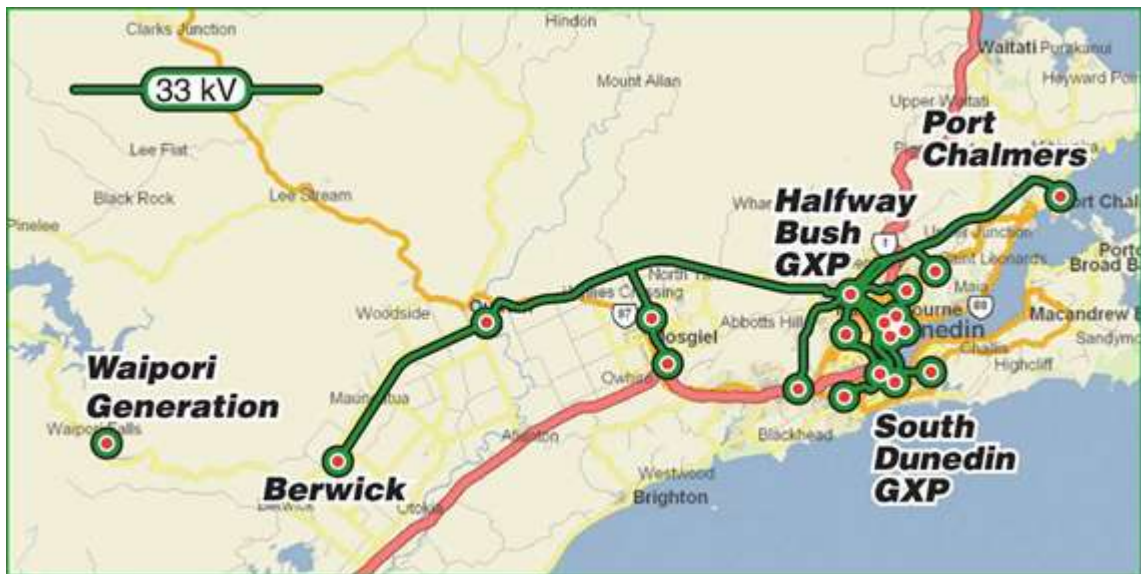


Figure 1 - Dunedin Pricing Area - South Dunedin and Halfway Bush GXPs



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

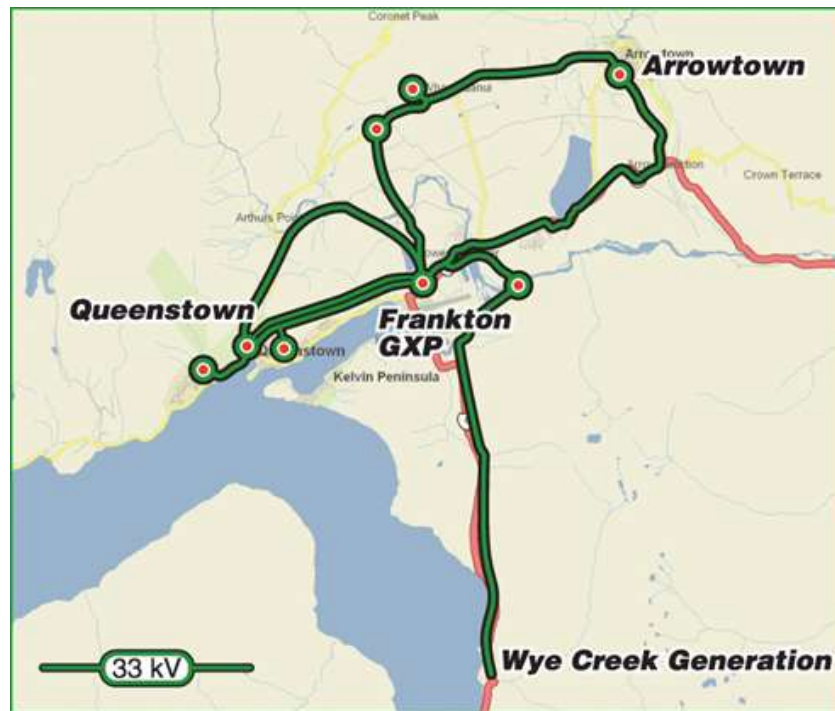


Figure 3 - Frankton Pricing Area - Frankton GXP

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 services¹. 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 disclosures². 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.

¹ See section 52T(1)(b) of the Commerce Act 1986.

² 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 connections³. 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 Congestion Period Demand Charge ensures that prices signal the impact of additional usage on future investment costs.

³ 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.

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.

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 Pricing⁴ 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 component⁵ 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 congestion period demand component of Aurora's tariffs provides a very strong signal for the investment in distribution alternatives.

⁴ 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.

⁵ 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 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.

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.

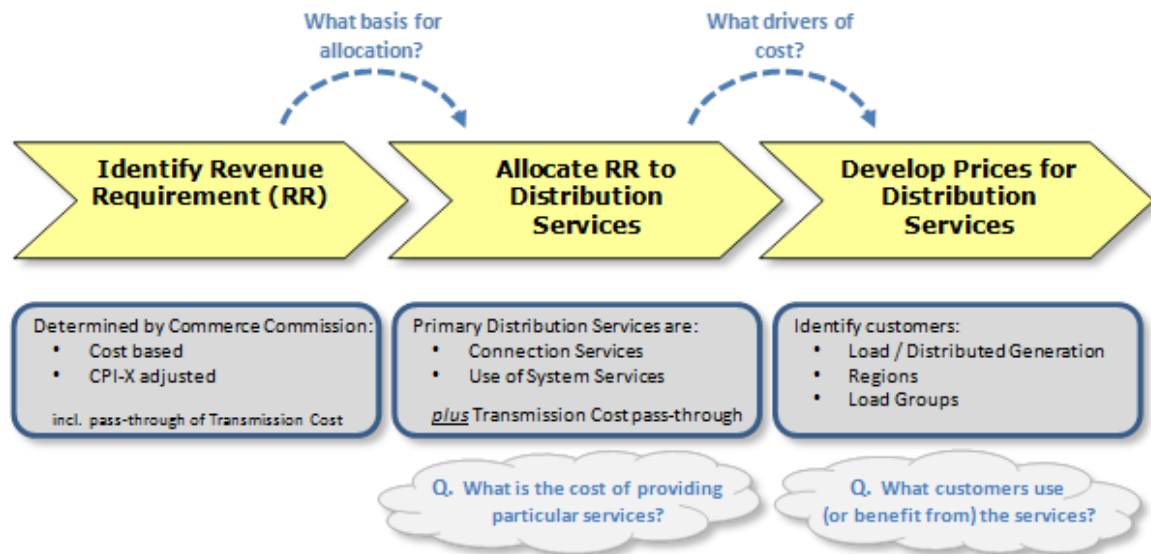


Figure 4 - Pricing Process

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 costs⁶) 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.

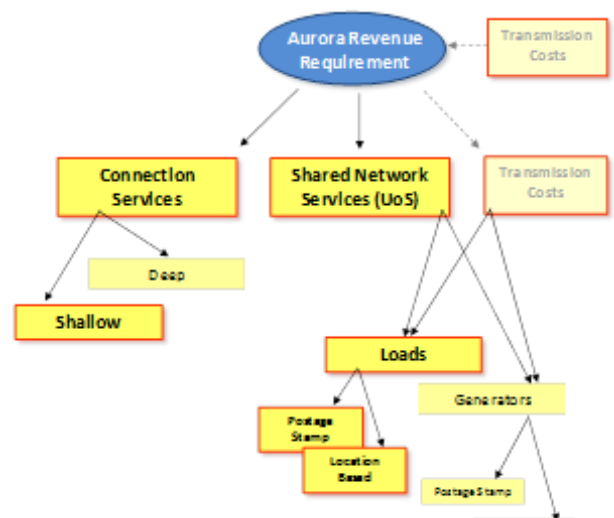


Figure 5 - Pricing Considerations

⁶ 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:

- meet its contractual obligations for connection to the Transpower grid;
- meet its contractual obligations for delivery of energy over the distribution network;
- comply with statutory requirements on public safety, environmental protection and quality of supply; and
- 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 costs⁷ should be allocated to:

- dedicated Connection services; and/or
- shared use-of-system services.

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

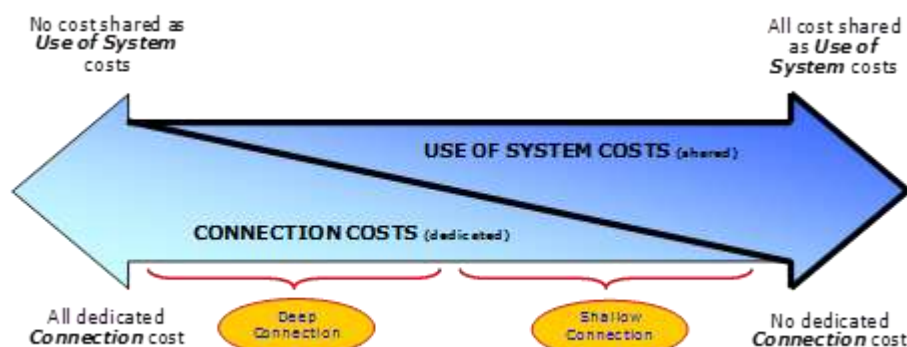


Figure 6 - Cost Allocation

⁷ Transmission costs have been ignored in this discussion of allocating the revenue requirement, as they are pass-through 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 signals⁸.

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.

⁸ 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 circuit distance from the distribution substation and the connection capacity in kVA); and
- kW demand charges (based on congestion period demand).

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 congestion period demand).

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.

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 Transmission Pricing Methodology

The Electricity Authority (EA) is currently consulting on changes to the Transmission Pricing Methodology (TPM). The EA's proposal would see a proportion of charges that are currently paid by Aurora (and recovered through prices) charged directly to electricity retailers and generators.

The EA considers that their proposal will deliver a \$173.2 million (net present value) benefit to consumers as a whole; however it not yet clear how those benefits may be allocated and it is conceivable that there may be winners and losers according to regional location and consumer size. Aurora has concerns that the EA's proposal may weaken the cost of service signals inherent in pricing, and reduce price stability and certainty for stakeholders, although it is accepted that the proposal is little more than a framework at this time, and greater certainty would emerge as Transpower develops its methodology, assuming that the proposal succeeds.

The EA has set a tentatively set 1 April 2015 as the commencement date for the new TPM.

3.2.2 Economic Framework for Distribution Pricing

Prior to consulting on changes to the TPM, described in section 3.2.1 above, the EA consulted on a decision-making and economic framework for transmission pricing. In 2012, the EA conducted a similar consultation on a decision-making and economic framework for distribution pricing that was largely consistent with the framework for transmission pricing.

The common approach to these frameworks leads Aurora to consider that there is a possibility that the EA will commence work on more prescriptive arrangements for distribution pricing methodologies when their work on the TPM is concluded.

Although Aurora considers that this use-of-system pricing methodology complies with the EA's pricing principles, and results in logical and cost reflective price derivation, there is a risk that regulatory intervention could occur to force industry standardisation, and that Aurora may be required to alter its price structures as a consequence.

3.2.3 *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 transmission components of congestion period demand charges.

On 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.

3.2.4 *Congestion Period Demand Review*

During the 2012 review of CPD, feedback was received from electricity retailers that the application of new CPD values from 1 October did not allow them sufficient time to notify their customers of the revised quantities. Aurora has agreed to consult with retailers during 2013, with view to revising the timeframe for applying the new CPD values following the post-winter review. Aurora is not proposing to review the CPD methodology nor amend the review period, and these matters will be excluded from consultation. If a new effective date is agreed, no specific notice will be given by Aurora with respect to this pricing methodology. Section 5.1.2.4 will simply be amended to reflect the change as part of the normal review and publication timetable that will occur prior to 31 March 2014.

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 causes Aurora to incur both distribution and transmission related 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 congestion 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 71% to 214%), as follows:

Grid Exit Point (GXP)	ORC ⁹	MW Peak ¹⁰	ORC / MW	
Clyde	\$78,886,585	17.4	\$4,533,712	214%
Cromwell	\$129,953,200	31.1	\$4,178,559	197%
Frankton	\$120,129,251	51.5	\$2,332,607	110%
Halfway Bush	\$191,587,250	126.6	\$1,513,327	71%
South Dunedin	\$104,072,086	68.7	\$1,514,878	72%
Totals	\$625,781,909	295.3	\$2,118,013 ¹¹	100%

Table 1 - Variation of \$ORC asset per MW

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 Transmission Costs

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.

⁹ 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.

¹⁰ MW peak is the average of the 12 highest peaks

¹¹ Average

The variation of these costs per MW of capacity provided for consumer use is significant between GXP (a range from 85% to 112%), as follows:

Grid Exit Point (GXP)	\$ / MW	% of average
Clyde	\$82,910	95%
Cromwell	\$73,977	85%
Frankton	\$97,579	112%
Halfway Bush	\$82,657	95%
South Dunedin	\$95,062	109%
Totals	\$87,246	100%

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

4.3 Combined Transmission and Distribution Costs

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

GXP Area	Transmission Cost	Distribution Cost	Composite Cost	Price Zone
<i>Weighting</i>	<i>30%</i>	<i>70%</i>	<i>100%</i>	
Clyde	95%	214%	177%	CYD & CML
Cromwell	85%	197%	162%	
Frankton	112%	110%	111%	FKN
Halfway Bush	95%	71%	79%	HWB & SDN
South Dunedin	109%	72%	83%	
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 20% 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 2014¹²

Target weighted average cost of capital		\$32.228 million
Expenses		\$33.187 million
<i>Network depreciation</i>	<i>\$12.845 million</i>	
<i>Other</i>	<i>\$20.343 million</i>	
Tax expense		\$12.576 million
Distribution costs		\$78.102 million
Transmission services		\$25.795 million
Full Delivery Costs		\$103.896 million
Less regulatory discount		-\$19.316 million
Target revenue budgeted for 2013/14		\$84.580 million
<i>Distribution</i>	<i>\$58.785 million</i>	
<i>Transmission</i>	<i>\$25.795 million</i>	

This revenue requirement is derived from the four pricing areas:

	Distribution	Transmission	Total
Dunedin HB & SDN area	\$28.581 million	\$16.995 million	\$45.576 million
Central CML & CYD area	\$19.128 million	\$3.982 million	\$23.110 million
Central FKN area	\$11.055 million	\$4.786 million	\$15.841 million
Heritage Estate	\$0.022 million	\$0.031 million ¹³	\$0.053 million
Total	\$58.785 million	\$25.795 million	\$84.580 million
<i>Weighting</i>	<i>70%</i>	<i>30%</i>	<i>100%</i>

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 (85) are so small that the breakdown by load group is less meaningful.

4.4.1 Underlying Drivers of the 2013 price changes

The underlying drivers for the 2013 price change are an increase in distribution costs, accompanied by a reduction in transmission expenses. The changes are quantified in Table 5 below:

Cost Category	Change from 2012
Cost of capital	\$2.084 million
Depreciation	\$1.043 million
Other network expenses	\$1.628 million
Taxation	\$0.772 million
Transmission expenses	-\$2.177 million

Table 5 - Price change drivers

¹² As Aurora has a 30 June balance date, budgets are not available for the June 2014 year and distribution costs have been taken from the budget for the June 2013 year adjusted for the expected revenues from 1 April 2013. Transmission costs reflect the expected transmission expenses for the year ending March 2014.

¹³ The transmission revenue requirement for the Heritage Estate area is the recovery of the line charges charged to Aurora by the parent network (The Power Company).

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	\$27.1 million	9%	\$2.070 million
Zone substations	\$74.4 million	25%	\$6.873 million
High voltage lines	\$88.6 million	30%	\$7.259 million
Distribution substations	\$41.1 million	14%	\$5.565 million
Low voltage lines	\$64.5 million	22%	\$6.814 million
Total	\$295.7 million	100%	\$28.581 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 Congestion Period Demand (MW)
S/L	0	2	8.1	1.7	11.6	1.1
L1	0 – 15	50,528	432.2	137.5	747.5	102.1
L2	16 – 149	2,984	144.5	32.7	150.3	25.5
L3	150 - 499	194	87.4	20.1	49.4	15.3
L4	500 – 2,499	71	114.8	31.0	56.7	17.0
L5	2,500+	8	61.6	13.7	29.9	8.6
Total		53,787	848.7	236.6	1,045.4	169.5

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 Congestion Period Demand.
- The costs for transmission have been allocated to load groups on the basis of Group Congestion Period Demand.

Cost Category	SL	L1	L2	L3	L4	L5	W33	Total
33kV lines	13	1,154	281	171	225	106	120	2,070
Zone substations	46	4,066	992	602	793	373		6,873
High voltage lines	50	4,473	1,097	663	873	109		7,259
Distribution substations	84	3,927	967	587				5,565
Low voltage lines	61	5,347	1,311	68				6,814
Total	254	18,994	4,642	2,091	1,892	587	120	28,581

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

Cost Category	SL	L1	L2	L3	L4	L5	W33	Total
Transmission	109	10,184	2,528	1,522	1,774	877		16,995

Table 9 - Dunedin pricing area load group allocation of transmission 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	\$18.9 million	9%	\$1.589 million
Zone substations	\$19.4 million	9%	\$2.489 million
High voltage lines	\$90.0 million	43%	\$9.168 million
Distribution substations	\$29.5 million	14%	\$3.216 million
Low voltage lines	\$51.1 million	24%	\$2.666 million
Total	\$208.8 million	100%	\$19.128 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 Congestion Period Demand (MW)
S/L	0	5	1.8	0.4	2.7	0.3
L1	0 – 15	15,662	108.0	39.9	228.3	32.8
L2	16 – 149	1,461	55.3	14.9	74.4	8.7
L3	150 - 499	97	25.2	7.9	21.4	3.3
L4	500 – 2,499	14	12.7	4.0	10.4	2.5
L5	2,500+					
Total		17,239	202.9	67.1	337.2	47.6

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 Congestion Period Demand.
- The costs for transmission have been allocated to load groups on the basis of Group Congestion Period Demand.

Cost Category	SL	L1	L2	L3	L4	L5	P33	Total
66kV and 33kV lines	6	732	230	107	65		448	1,589
Zone substations	14	1,597	503	234	141			2,489
High voltage lines	51	5,884	1,852	862	519			9,168
Distribution substations	34	2,173	689	321				3,216
Low voltage lines	17	1,951	617	80				2,666
Total	122	12,338	3,891	1,603	724		448	19,128

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

Cost Category	SL	L1	L2	L3	L4	L5	P33	Total
Transmission	22	2,693	747	304	216			3,982

Table 13 - Clyde / Cromwell pricing area load group allocation of transmission 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	\$7.1 million	6%	\$594 million
Zone substations	\$18.4 million	15%	\$2.067 million
High voltage lines	\$44.8 million	37%	\$4.493 million
Distribution substations	\$15.5 million	13%	\$1.725 million
Low voltage lines	\$34.3 million	29%	\$2.175 million
Total	\$120.1 million	100%	\$11.055 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 Congestion Period Demand (MW)
S/L	0	3	1.1	0.2	1.7	0.2
L1	0 – 15	10,433	92.9	31.9	151.8	29.6
L2	16 – 149	1,293	58.4	14.3	61.8	10.6
L3	150 - 499	64	21.0	7.9	16.1	4.4
L4	500 – 2,499	21	32.7	6.8	14.3	5.9
L5	2,500+	1	5.1	2.0	5.2	1.0
Total		11,815	210.5	63.0	250.8	51.6

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 Congestion Period Demand.
- The costs for transmission have been allocated to load groups on the basis of Group Congestion Period Demand.

	SL	L1	L2	L3	L4	L5	P33	Total
33kV lines	2	320	128	62	66	15		594
Zone substations	7	1,114	447	217	229	53		2,067
High voltage lines	16	2,474	992	482	508	21		4,493
Distribution substations	17	1,066	432	210				1,725
Low voltage lines	10	1,498	602	65				2,175
Total	52	6,473	2,601	1,036	803	89		11,055

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

	SL	L1	L2	L3	L4	L5	P33	Total
Transmission	16	2,646	1,014	462	537	111		4,786

Table 17 - Frankton pricing area load group allocation of transmission costs

5 PRICING COMPONENTS

5.1 Distribution Cost-Recovery Components

5.1.1 Standard Domestic Connections

A "Standard Domestic" connection is one where the connection capacity is either 15 kVA (single phase 60 amps) or 8 kVA (single phase 32 amps) and the electricity retailer advises Aurora that the electricity use is for domestic purposes.

In order to comply with this the premises will generally be as described in the definition of "domestic" under the Electricity Amendment Act 2001.

"Domestic premises" means any premises that are used or intended for occupation by any person principally as a place of residence, but does not include –

- penal institutions;
- hospitals, homes or other institutions for care of sick, aged or disabled;
- police barracks;
- armed forces barracks;
- 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). 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, 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.

- *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 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 *Congestion 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 Congestion 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 Congestion Period the accumulated energy is divided by the duration of the Congestion Period to obtain average power demand. If a consumer commences during the year a negotiated Congestion Period Demand will apply until a full winter is completed. The Congestion Period Demand for each installation is set at 1 October to the average of CPD kW (Previous Winter) and CPD kW (at 1 October previous year).

The Congestion 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. The congestion will be signalled via ripple control whenever the Congestion Period applies. Consumers may use this 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 Congestion Period Demand metering for connections such as Load Group 1 and 2, then any charges that would normally be recovered via a Congestion Period Demand charge will be recovered via an Effective Congestion 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 are discounted 100% and energy used by controlled loads are discounted 50% for their daytime energy.

The list of discount rates for kWh usage on each controlled rate register is set out in Schedule 6. The effective Congestion Period Demand for each installation is set at 1 October to the average of CPD kW (Previous Winter) and CPD kW (at 1 October previous year). Thus a strong economic signal exists for consumers to accept controlled loads.

By signalling network congestion in this way, Aurora is able to defer the need for investment in more capacity, which is a very expensive alternative. Load is controlled only when the network loading is approaching the network's capacity. 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 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 Transmission Cost-Recovery Components

5.2.1 Connection Charges

These charges have been allocated to load groups on the basis of each load group's share of anytime demand. This improves the signalling of investment costs to those users who cause them.

5.2.2 Interconnection Charges

These charges have been allocated to each load group on the basis of the congestion period demand of each load group. The congestion period demand is the average demand of each load group whilst the load control service is being applied at the time of system load peaks. This is expected to apply for approximately 150 to 200 hours per year and mainly during the winter months of June, July and August.

5.2.3 Standard Domestic Supply

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

For other L1A (8 kVA) and other L1 (15 kVA) connections and the L2 (16-149 kVA) load group the connection charges are recovered by way of a charge per installed kVA capacity and the interconnection charge by way of a \$/kW using the previous year's winter day average demand.

For the L3 (150-249 kVA), L3A (250-499 kVA), L4 (500-2499 kVA) and L5 (2500+ kVA) load groups, the connection charges are recovered by way of a charge per installed kVA capacity and the interconnection charge by way of a charge per congestion period demand kW.

5.2.4 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 retailers total transmission charges for the month in which the rebate applied. This credit is currently available in say mid-June for the month of April.

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	Fixed	\$3,067	\$996	\$644	\$7	\$4,714
	Variable	\$14,871	\$10,136	\$5,117	\$34	\$30,159
	Capacity	\$5,168	\$3,873	\$2,707	\$0	\$11,749
	kVA-km	\$240	\$432	\$145		\$817
	CPD	\$4,295	\$3,080	\$2,267	\$0	\$9,642
	Equipment	\$566	\$35	\$116		\$717
	Street lighting	\$254	\$128	\$58	\$2	\$442
	Generation	\$120	\$449			\$568
	<i>Subtotal</i>	<i>\$28,561</i>	<i>\$19,128</i>	<i>\$11,055</i>	<i>\$44</i>	<i>\$58,808</i>
Transmission	Fixed	\$23	\$29	\$22	\$0	\$73
	Variable	\$9,136	\$2,337	\$2,276	\$9	\$13,758
	Capacity	\$1,011	\$54	\$439	\$0	\$1,504
	CPD	\$6,715	\$1,540	\$2,030	\$0	\$10,286
	Street lighting	\$109	\$22	\$20	\$0	\$151
	<i>Subtotal</i>	<i>\$16,995</i>	<i>\$3,982</i>	<i>\$4,786</i>	<i>\$9</i>	<i>\$25,772</i>
Total		\$45,576	\$23,110	\$15,841	\$53	\$84,580

Table 18 - Target Revenue by Price Component

6 SEASONAL LOADS

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 congestion 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

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.
- 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.
- h) Use-of-system charges closely follow the methodology recommended by the Ministry of Commerce document "Electricity Disclosure Guidelines 1994" and modified (as discussed previously) to meet the Government's regulatory requirement for Standard Domestic consumers. The methodology is also consistent with the Model Approaches to Distribution Pricing formulated by an industry group in 2004. These guidelines recommend revenue allocations by load groups according to their general usage of asset classes.

8 NON STANDARD CONTRACTS

Aurora has not entered into any non-standard contract. Aurora has a conveyance agreement with Pioneer Generation Limited for a number of irrigation pumps (Fraser Pumps Agreement); however, the agreement is subject to Aurora's standard pricing arrangements and the commercial terms are in all material respects standard.

9 DISTRIBUTED GENERATION

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 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. 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 transmission 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 class¹⁴. Accordingly, the calculation will be:

¹⁴ 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 \$1.5M, and 33kV zone substation equipment with an RC of \$0.8M, 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 \$20M, and all zone substation equipment is \$27M. Maintenance of Central Otago subtransmission equipment is budgeted at \$350k, and zone substation equipment at \$300k.

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:

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

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

CPD	congestion 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
TPM	transmission pricing methodology

SCHEDULE A – PRICES - SOUTH DUNEDIN AND HALFWAY BUSH GRID EXIT POINTS

Effective: 1 April 2013

A.1 – STANDARD DOMESTIC CONNECTIONS		Registry Code	Per Annum	
			Distribution	Transmission
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	010S	5.45	1.75
General Purpose	All day Winter	010W	6.50	4.33
Controlled Variable Charges		Tariff Code	(¢ / kWh)	
General Purpose + 16 hour water heat	All day Summer	017s	2.72	1.70
General Purpose + 16 hour water heat	All day Winter	017W	4.08	2.58
Night + 3 hours		024	1.44	0.56
Night rate		028	0.38	
Gen Purpose + 16 hour w/h – D/N	Summer Day	011S	4.88	1.73
Gen Purpose + 16 hour w/h – D/N	Winter Day	011W	5.48	4.48
Gen Purpose + 16 hour w/h – D/N	Summer Night	012S	0.38	
Gen Purpose + 16 hour w/h – D/N	Winter Night	012W	0.38	

A.2 – STREET LIGHTING		Registry Code	Per Annum	
			Distribution	Transmission
Fixed Annual Charge	0000201300DE692	SDNSTL	\$85,921	\$37,012
Fixed Annual Charge	0000203111DE930	HWBSTL	\$167,951	\$72,348

A.3 – OTHER CONNECTIONS				Per Annum			
Registry Code		Load Group	Capacity (kVA)	Fixed (\$)	Capacity (\$ / kVA)	kVA-km (\$ / kVA-km)	Congestion Period (\$ / kW)
Distribution	SH0	L0	0 - 1	\$105.81			
	SH0A	L0A (note 5)	0 - 2	\$219.67			
	SH1A	L1A (note 6)	0 - 8	\$10.01	\$12.15		\$91.31
	SH1	L1	0 - 15	\$10.01	\$10.69		\$91.31
	SH2	L2 (note 8)	16 - 149	\$21.57	\$14.40		\$91.31
	SH3	L3	150 - 249	\$393.00	\$24.10	\$0.27	\$53.90
	SH3A	L3A	250 - 499	\$393.00	\$22.25	\$0.27	\$53.90
	SH4	L4 (note 9)	500 – 2,499	\$988.00	\$14.12	\$0.27	\$52.10
	SH5	L5 (note 9)	2,500 +	\$988.00	\$7.07	\$0.27	\$32.65
Transmission	SH0	L0	0 - 1	\$69.00			
	SH0A	L0A (note 5)	0 - 2	\$149.02			
	SH1A	L1A (note 6)	0 - 8		\$6.99		\$91.82
	SH1	L1	0 - 15		\$5.85		\$91.82
	SH2	L2	16 - 149		\$1.39		\$91.82
	SH3	L3	150 - 249		\$3.70		\$90.00
	SH3A	L3A	250 - 499		\$3.70		\$90.00
	SH4	L4	500 – 2,499		\$3.27		\$90.00
	SH5	L5	2,500 +		\$2.08		\$90.00

A.4 – GENERATION		Per Annum		
Generator	Connection	HVDC Recovery	Avoided Transmission	
TrustPower Ltd	\$119,932.00	\$876,405.73	-\$5,088,991.16	

SCHEDULE B – PRICES - CLYDE AND CROMWELL GRID EXIT POINTS

Effective: 1 April 2013

B.1 – STANDARD DOMESTIC CONNECTIONS		Registry Code	Per Annum	
			Distribution	Transmission
Fixed Annual Charge (15 kVA)		CCSD15	\$54.73	
Fixed Annual Charge (8 kVA) (note 6)		CCSD8	\$15.00	
Uncontrolled Variable Charges		Tariff Code	(¢ / kWh)	
General Purpose	All day Summer	101S	10.40	1.75
General Purpose	All day Winter	101W	14.32	3.96
Controlled Variable Charges		Tariff Code	(¢ / kWh)	
Peak Water Heating	20 hour service	109	7.58	2.11
Standard Water Heating	16 hour service	106	5.48	1.24
Night + 5 Hours	13 hour service	103	6.17	1.79
Night + 3 Hours	11 hour service	104	5.06	0.94
Night		108	4.32	

B.2 – STREET LIGHTING	Registry / Tariff Code	(¢ / kWh)	
Fixed Annual Charge per lamp	CCSTL	\$13.56	
Variable Charge	110	4.06	1.22

B.3 – OTHER CONNECTIONS				Per Annum			
Registry Code		Load Group	Capacity (kVA)	Fixed (\$)	Capacity (\$ / kVA)	kVA-km (\$ / kVA-km)	Congestion Period (\$ / kW)
Distribution	CC0	L0	0 - 1	\$200.42			
	CC0A	L0A (note 5)	0 - 2	\$382.11			
	CC1A	L1A (note 6)	0 - 8	\$13.54	\$31.81		\$186.76
	CC1	L1	0 - 15	\$13.54	\$29.47		\$186.76
	CC2	L2 (note 8)	16 - 149	\$28.44	\$27.98		\$186.18
	CC3	L3	150 - 249	\$542.00	\$31.60	\$0.37	\$192.12
	CC3A	L3A	250 - 499	\$542.00	\$28.35	\$0.37	\$192.12
	CC4	L4 (note 9)	500 – 2,499	\$1,424.00	\$18.61	\$0.37	\$140.93
	CC5	L5 (note 9)	2,500 +	\$1,424.00	\$16.58	\$0.37	\$130.64
Transmission	CC0	L0	0 - 1	\$56.04			
	CC0A	L0A (note 5)	0 - 2	\$141.04			
	CC1A	L1A (note 6)	0 - 8		\$1.91		\$88.12
	CC1	L1	0 - 15		\$0.90		\$88.12
	CC2	L2	16 - 149		\$0.53		\$80.31
	CC3	L3	150 - 249		\$0.77		\$84.40
	CC3A	L3A	250 - 499		\$0.77		\$84.40
	CC4	L4	500 – 2,499		\$0.46		\$84.40
	CC5	L5	2,500 +		\$0.46		\$84.40

B.4 – GENERATION		Per Annum		
Generator	Connection	HVDC Recovery	Avoided Transmission	
Pioneer Generation Ltd	\$423,037.00	\$614,511.63	-\$1,501,876.16	
Talla Burn Generation Ltd	\$25,463.00	\$70,354.60	-\$110,706.74	

SCHEDULE C – PRICES - FRANKTON GRID EXIT POINT

Effective: 1 April 2013

C.1 – STANDARD DOMESTIC CONNECTIONS		Registry Code	Per annum	
			Distribution	Transmission
Fixed Annual Charge (15 kVA)		FRSD15	\$54.73	
Fixed Annual Charge (8 kVA) (note 6)		FRSD8	\$15.00	
Uncontrolled Variable Charges		Tariff Code	(¢ / kWh)	
General Purpose	All day Summer	201S	7.37	2.04
General Purpose	All day Winter	201W	9.56	4.53
Controlled Variable Charges		Tariff Code	(¢ / kWh)	
Peak Water Heating	20 hour service	209	4.43	1.95
Standard Water Heating	16 hour service	206	1.98	1.37
Night + 5 Hours	13 hour service	203	2.90	1.71
Night + 3 Hours	11 hour service	204	1.77	0.90
Night		208	1.28	0.00

C.2 – STREET LIGHTING	Registry / Tariff Code	(¢ / kWh)	
Fixed Annual Charge per lamp	FRSTL	\$13.56	
Variable Charge	210	1.61	1.43

C.3 – OTHER CONNECTIONS				Per Annum			
Registry Code		Load Group	Capacity (kVA)	Fixed (\$)	Capacity (\$ / kVA)	kVA-km (\$ / kVA-km)	Congestion Period (\$ / kW)
Distribution	FR0	L0	0 - 1	\$138.33			
	FR0A	L0A (note 5)	0 - 2	\$250.63			
	FR1A	L1A (note 6)	0 - 8	\$12.07	\$19.10		\$88.82
	FR1	L1	0 - 15	\$12.07	\$18.01		\$88.82
	FR2	L2 (note 8)	16 - 149	\$19.62	\$21.43		\$106.71
	FR3	L3	150 - 249	\$445.00	\$44.31	\$0.35	\$73.28
	FR3A	L3A	250 - 499	\$445.00	\$41.16	\$0.35	\$73.28
	FR4	L4 (note 9)	500 – 2,499	\$1,173.00	\$24.03	\$0.35	\$69.88
	FR5	L5 (note 9)	2,500 +	\$1,173.00	\$3.30	\$0.35	\$50.49
Transmission	FR0	L0	0 - 1	\$63.40			
	FR0A	L0A (note 5)	0 - 2	\$143.57			
	FR1A	L1A (note 6)	0 - 8		\$8.30		\$86.03
	FR1	L1	0 - 15		\$7.77		\$86.03
	FR2	L2	16 - 149		\$1.08		\$86.03
	FR3	L3	150 - 249		\$8.38		\$78.00
	FR3A	L3A	250 - 499		\$8.38		\$78.00
	FR4	L4	500 – 2,499		\$4.43		\$78.00
	FR5	L5	2,500 +		\$7.99		\$78.00

SCHEDULE D – PRICES - FRANKTON GRID EXIT POINT¹⁵

Effective: 1 April 2013

D.1 – STANDARD DOMESTIC CONNECTIONS		Registry Code	Per annum	
			Distribution	Transmission
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	301S	7.37	2.04
General Purpose	All day Winter	301W	9.56	4.53
Controlled Variable Charges		Tariff Code	(¢ / kWh)	
Peak Water Heating	20 hour service	309	4.43	1.95
Standard Water Heating	16 hour service	306	1.98	1.37
Night + 5 Hours	13 hour service	303	2.90	1.71
Night + 3 Hours	11 hour service	304	1.77	0.90
Night		308	1.28	

D.2 – STREET LIGHTING		Registry / Tariff Code	(¢ / kWh)	
Fixed Annual Charge per lamp		FKSTL	\$13.56	
Variable Charge		310	1.61	1.43

D.3 – OTHER CONNECTIONS				Per Annum			
Registry Code		Load Group	Capacity (kVA)	Fixed (\$)	Capacity (\$ / kVA)	kVA-km (\$ / kVA-km)	Congestion Period (\$ / kW)
Distribution	FK0	L0	0 - 1	\$138.33			
	FK0A	L0A (note 5)	0 - 2	\$250.63			
	FK1A	L1A (note 6)	0 - 8	\$12.07	\$19.10		\$88.82
	FK1	L1	0 - 15	\$12.07	\$18.01		\$88.82
	FK2	L2 (note 8)	16 - 149	\$17.66	\$19.29		\$96.04
	FK3	L3	150 - 249	\$367.13	\$36.56	\$0.35	\$60.46
	FK3A	L3A	250 - 499	\$367.13	\$33.96	\$0.35	\$60.46
	FK4	L4 (note 9)	500 – 2,499	\$909.08	\$18.62	\$0.35	\$54.16
	FK5	L5 (note 9)	2,500 +	\$909.08	\$2.56	\$0.35	\$39.13
Transmission	FK0	L0	0 - 1	\$63.40			
	FK0A	L0A (note 5)	0 - 2	\$143.57			
	FK1A	L1A (note 6)	0 - 8		\$8.30		\$86.03
	FK1	L1	0 - 15		\$7.77		\$86.03
	FK2	L2	16 - 149		\$1.08		\$86.03
	FK3	L3	150 - 249		\$8.38		\$78.00
	FK3A	L3A	250 - 499		\$8.38		\$78.00
	FK4	L4	500 – 2,499		\$4.43		\$78.00
	FK5	L5	2,500 +		\$7.99		\$78.00

¹⁵ Sub area – note 15

SCHEDULE E – PRICES – HERITAGE ESTATE EMBEDDED SUBDIVISION, TE ANAU

(Note 12)

Effective: 1 June 2012

E.1 – STANDARD DOMESTIC CONNECTIONS		Registry Code	Per annum	
			Distribution	Transmission
Fixed Annual Charge (15 kVA)		HESD15	\$54.73	
Fixed Annual Charge (8 kVA) (note 6)		HESD8	\$15.00	
Uncontrolled Variable Charges		Tariff Code	(¢ / kWh)	
General Purpose	All day Summer	401S	7.55	2.32
General Purpose	All day Winter	401W	9.28	5.59
Controlled Variable Charges		Tariff Code	(¢ / kWh)	
Standard Water Heating	16 hour service	406	2.98	1.64
Night + 3 Hours	11 hour service	404	2.74	1.36
Night		408	2.73	

E.2 – STREET LIGHTING	Registry / Tariff Code	(¢ / kWh)	
Fixed Annual Charge per lamp	HESTL	\$13.56	
Variable Charge	410	4.47	1.94

E.3 – OTHER CONNECTIONS				Per Annum			
Registry Code		Load Group	Capacity (kVA)	Fixed (\$)	Capacity (\$ / kVA)	kVA-km (\$ / kVA-km)	Congestion Period (\$ / kW)
Distribution	HE0	L0	0 - 1	\$150.56			
	HE0A	L0A (note 5)	0 - 2	\$280.68			
	HE1A	L1A (note 6)	0 - 8	\$11.28	\$23.13		\$139.69
	HE1	L1	0 - 15	\$11.28	\$21.38		\$139.69
	HE2	L2 (note 8)	16 - 149	\$22.57	\$24.12		\$128.05
Transmission	HE0	L0	0 - 1	\$62.48			
	HE0A	L0A (note 5)	0 - 2	\$157.26			
	HE1A	L1A (note 6)	0 - 8		\$1.48		\$95.12
	HE1	L1	0 - 15		\$0.27		\$95.12
	HE2	L2	16 - 149		\$0.15		\$88.11

SCHEDULE F – NOTES TO PRICE SCHEDULES

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. 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 transmission 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.

Register Contents	Pricing Code Dunedin		Pricing Code Clyde/Cromwell		Pricing Code Frankton		Pricing Code Frankton sub area		Pricing Code Heritage Estate		CPD kW Discount
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	
IN19	017S	017W									42%
UN24	010S	010W	101S	101W	201S	201W	301S	301W	401S	401W	Nil
CN11	024	024	104	104	204	204	304	304	404	404	75%
CN8	028	028	108	108	208	208	308	308	408	408	100%
IN16	011S	011W	-	-	-	-	-	-	-	-	20%
IN8	012S	012W	-	-	-	-	-	-	-	-	100%
CN20	-	-	109	109	209	209	309	309	-	-	25%
CN16	006	006	106	106	206	206	306	306	-	-	50%
CN13	-	-	103	103	203	203	303	303	-	-	60%
CN10	-	-	145	145	245	245	345	345	-	-	100%
DC16	013	013	-	-	-	-	-	-	-	-	50%
NC8	014	014	-	-	-	-	-	-	-	-	100%
D16	015	015	115	115	215	215	315	315	415	415	Nil
N8	016	016	116	116	216	216	316	316	416	416	100%
GENPV	090	090	190	190	290	290	390	390	490	490	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 5.4.5
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 & 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-	Clause 2.4.3 (5)	Sections 3.1.4 & 4.5
(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		
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 3.1
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	Clause 2.4.5 (3)	Section 9.2
prices; and	Clause 2.4.5 (3) (a)	Schedules A & B
value, structure and rationale for any payments to the owner of the distributed generation.	Clause 2.4.5 (3) (b)	Section 9.4