
Use-of-System Pricing Methodology

31 March 2017

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1 Purpose

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

2 Scope

The document applies to the pricing of all electricity lines services, regulated under Part 4 of the Commerce Act 1986.

3 Accountabilities

Aurora Board of Directors	Accountable for certifying this document in accordance with clause 2.9.1 of the Electricity Distribution Information Disclosure Determination 2012.
General Manager Network Commercial (Delta)	Accountable for ensuring this document is reviewed annually and publicly disclosed in accordance with clause 2.4.1 of the Electricity Distribution Information Disclosure Determination 2012.

4 Definitions

Aspect.	Definition.
Code	means the Electricity Industry Participation Code
CPD	means control period demand
CPI	means the consumers' price index published by Statistics New Zealand
CPI-X	means a rate of change, linked to CPI, as determined by the Commerce Commission and published in the Electricity distribution Services Default Price-Quality Path Determination 2015
EA	means the Electricity Authority
EDB	means electricity distribution business
ENA	means the Electricity Networks Association
GWh	means gigawatt hour
GXP	means grid exit point
HV	means high voltage
HVDC	means high voltage direct current
Km	means kilometre
kVA	means kilovolt-ampere
kW	means kilowatt
kWh	means kilowatt hour

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Aspect.	Definition.
ICP	means installation control point, and is further defined in the Code
LV	means low voltage
MVA	means megavolt ampere
MW	means megawatt
DRC	means depreciated replacement cost
ORC	means replacement cost
SSDG	means small-scale distributed generation
TMP	Means transmission pricing methodology

5 Changes to Pricing Methodology

There has been no material change to Aurora's pricing methodology since last publication; however, Aurora amended the qualification criteria for some price options and clarified the definition of one consumer segment, as a result of a consultation performed in 2016.

5.1 Retailer Consultation

A consultation paper setting out proposed amendments to Aurora's use-of-system pricing methodology was sent to all connected electricity retailers in November 2016. The consultation paper contained three separate proposals to:

- Close the all-inclusive price options to new consumers in Dunedin;
- Clarify the definition of a Residential consumer; and
- Change the treatment of Loss and Constraint Excess Payments.

Six retailers responded to the consultation, and the respondents were supportive of Aurora's clarification of a Residential consumer, and the proposal to close the all-inclusive price option in Dunedin. Sections 10.1 and 11.1.1 outline the details of these minor amendments.

Aurora received conflicting feedback as to whether loss and constraint rental rebates should be retained by Aurora and included in prices. This proposal was not implemented, pending further advice and consideration by Aurora.

Section 8 has been updated to reflect likely pricing responses to prevailing and emerging conditions and to signal the likely future direction of Aurora's pricing approach.

6 Introduction

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

6.1 Customer Consultation

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

- Customers still consider price to be more important than quality of supply, and that there is little appetite to accept an increase in delivery prices to achieve a proportionate improvement in quality; and

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- The frequency of interruptions remains the single most important issue relating to quality of supply.

It is recommended that interested persons wishing to understand more about Aurora's customer 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 customers and other stakeholders and ensures that sufficient revenue is generated in order to meet future asset improvement programmes.

6.2 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. Figure 1, below, shows the geographic arrangement of the network. Aurora also operates a small embedded network (residential subdivision) at Te Anau, which takes supply from The Power Company network.

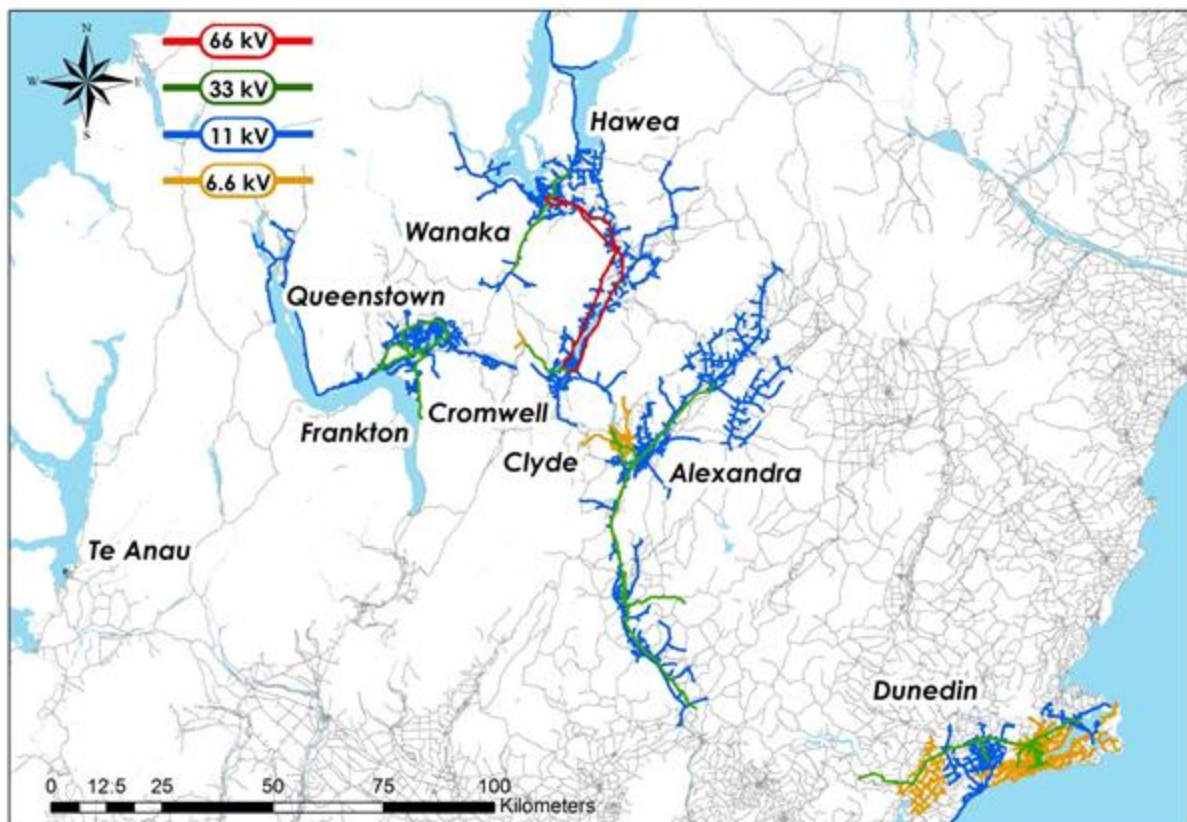


Figure 1 - Aurora Distribution Network

6.3 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.

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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.

6.4 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;*

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

² See section 53C(2)(c) of the Commerce Act 1986.

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- 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 price 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.

6.5 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 prices 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 price ensures prices have regard to the level of available service capacity, and similarly, the use of a Control Period Demand price ensures that prices signal the impact of additional usage on future investment costs.

It is Aurora's intention that these prices, in combination, should promote the efficient utilisation of the network's available capacity. Where new investment is required, it is also

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.

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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 price categories (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 price structure – e.g. the fixed and volumetric components of the prices. 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 Residential 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 prices for Residential 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 price 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 control period demand component of Aurora's prices provides a very strong signal for the investment in distribution alternatives.

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

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.

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- 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 price component in 1996. At the time Aurora ensured a phasing-in of this price component to minimise the impact on remote connections.

- Pricing Principle (e) Regard to Downstream Competition Impacts

Aurora's prices 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/impered by numerous or overly complex price structures.

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

6.6 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 Authority.

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

- How the methodology links to the pricing principles (Section 6.3)
- The rationale for consumer groupings and the method for determining the allocation of consumers to the consumer groupings (Sections 9.5 and 10)
- Quantification of key components of costs and revenues (Section 9)
- An explanation of the cost allocation methodology and the rationale for the allocation to each consumer grouping (Section 9)
- An explanation of the derivation of the prices to be charged to each consumer group and the rationale for the pricing design (Section 11).

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7 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 2, 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.

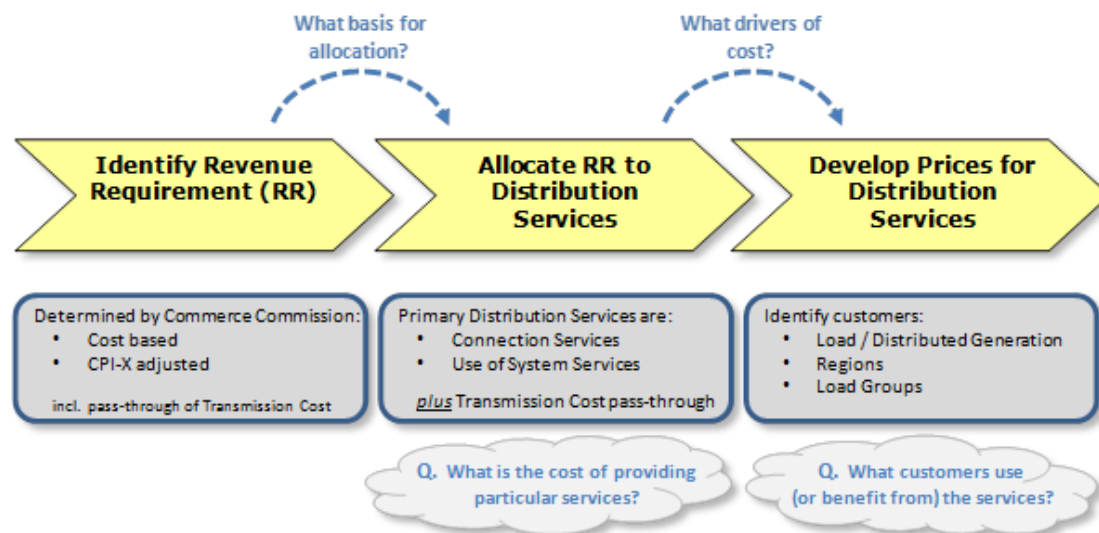


Figure 2 - Pricing Process

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

7.1 Description of Aurora's Pricing Methodology

Figure 3 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.

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)

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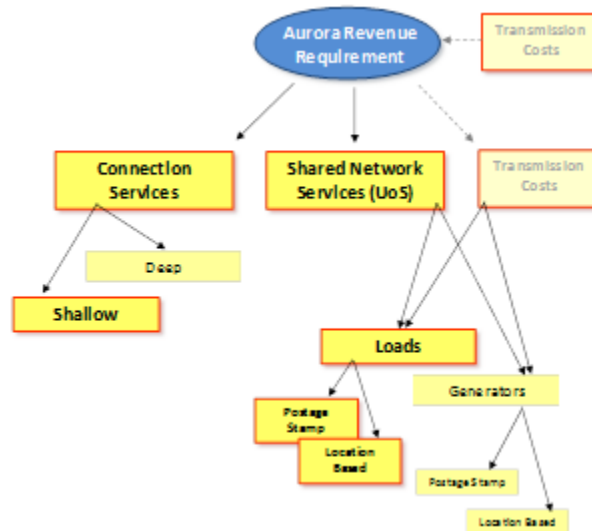


Figure 3 - Pricing Considerations

7.1.1 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 9.

7.1.2 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:

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

⁷ Transmission costs have been ignored in this discussion of allocating the revenue requirement, as they are recoverable costs, and Aurora treats transmission costs in a similar manner to 'use-of-system' costs.

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There is no 'right' allocation, and the spectrum of possibilities is depicted in Figure 4, below:

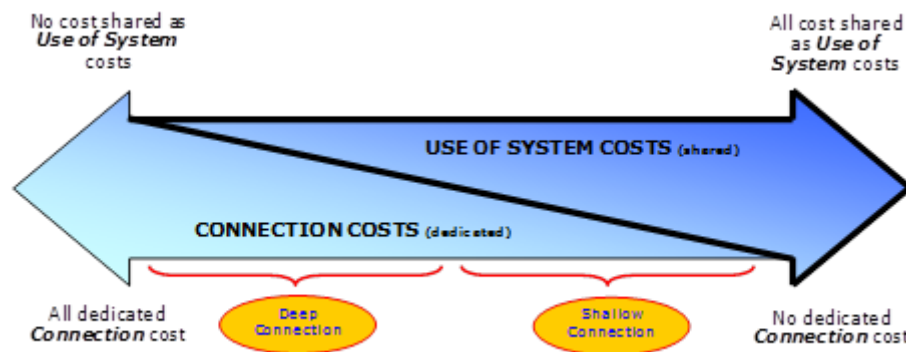


Figure 4 - Cost Allocation

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.

⁸ For instance, new load customers may be attracted to locations where the existing connection infrastructure has lower costs.

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7.1.3 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.

7.1.4 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 delivery prices.

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 9.1 to 9.3. 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 9.5. 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 price 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 residential 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 residential consumer demands.

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

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

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

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

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

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

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

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For smaller consumers (i.e. price codes L1 and L1A) which also satisfy the definition for "residential" (refer to section 10.1), costs are recovered through:

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

This price structure for smaller residential 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 prices (as per the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004). These regulations require residential consumers using up to 9,000 kWh per annum to have, as an option, the fixed portion of their delivery prices 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 residential consumers, with the main weakness being that actual capacity costs are not recovered from consumers that use low kWh volumes. This weakness is increasingly being exacerbated by the deployment of Small-Scale Distributed Generation (SSDG), and is also giving rise to issues of equity, since consumers that can afford SSDG systems inevitably shift the burden of network cost recovery to consumers that cannot afford such systems.

The determination of load groups and the structure of load group prices for each pricing area are detailed more fully in Sections 9.5 and 11 respectively.

8 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:

8.1 Strategic Review of Aurora's Pricing Methodology

Aurora commenced, in December 2015, a strategic review of Aurora's pricing methodology. The purpose of the review is two-fold:

1. To seek assistance in closing compliance gaps, with regard to the Electricity Authority's pricing principles and information disclosure requirements, identified by Castalia in its 2013 review of EDB's pricing methodologies; and
2. To critique the efficacy of Aurora's pricing methodology and develop innovative options for improving and developing pricing structures that start to address some of the developing / maturing technology issues facing Aurora. This includes options for managing the impact of poorly conceived regulatory constraints – the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 in particular.

This work will also address some of the issues detailed in sections 8.2 to 8.6, below.

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8.2 Distribution Pricing Reform

The Electricity Authority announced in October 2016 that, as part of its next steps in its ongoing Distribution Pricing Review, it had an expectation that distributors would, by 1 April 2017, publish their plans for introducing more efficient pricing. Specifically, Authority statement of expectation stated that distributors should include in their plans:

- a clear outline of the process each distributor will adopt, including the nature of their planned consultation with retailers and consumers;
- a timeline with the key milestones; and
- resourcing implications, including how resources will be allocated to the process of moving towards efficient pricing structures.

8.2.1 Aurora's intended process

Aurora has a commercial interest in ensuring prices are as cost reflective (i.e. efficient) as practicable. Cost reflective network pricing (when transparently reflected through retail prices) will provide appropriate commercial incentives to consumers to moderate their electricity use, or use on-site generation / storage, during times of high network demand. Conversely, it will incentivise consumers to use electricity, or charge their storage facility, during times of low network demand.

As all distributors in New Zealand are subject to similar commercial pressures, Aurora has been an active participant in ENA working groups and forums over the past few years. This allows Aurora to understand the learnings of other distributors in relation to pricing reform, and to contribute to pricing guidance issued by the ENA for all distributors.

Schedule I outlines Aurora's Future Pricing Roadmap (FPR), which is presented in a template provided by the ENA. The FPR outlines the key stages of implementing more cost reflective pricing, the activities that are required to be performed at each stage, and when these activities are going to take place. The FPR is expected to evolve as the project progresses, and will be updated annually.

Aurora's FPR has grouped the transition to more cost reflective pricing into four main stages:

- Initiate the cost-reflective pricing plan;
- Regulatory enablers;
- Plan changes in more detail; and
- Manage roll out of new pricing options.

8.2.2 Timeline & key milestones

During the initiation phase, Aurora plans to communicate with retailers regarding its strategy for pricing change. This is already underway through Aurora's periodic consultation with retailers, and Aurora's support for the ENA's "New Pricing Options for Electricity Distributors" paper, which both occurred in 2016. However, Aurora's plans to have further discussion with retailers over the next two years and to issue its own guidance on future pricing by mid-2019.

Following consultation with retailers, Aurora will develop more detailed plans and strategies for future pricing. At this point we will commence a broader consultation and education programme on the likely composition of future pricing. Consultation with consumers will be valuable at this point, as the future strategy will be more refined. Aurora is concerned that premature consultation has the potential to confuse, rather than educate, given consumers' general lack of awareness of distribution pricing.

Between the retailer consultation and the consumer consultation phases, the 2020 change in the form of control for distributors under Part 4 of the Commerce Act 1986 (from a weighted average price cap to a revenue cap) becomes a key regulatory enabler for pricing reform. The current weighted average price cap exposes Aurora to significant risk of breaching its regulated price-path when the structure of prices are changed, particularly where the customer responses to these changes are unknown.

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Following consumer consultation, Aurora will move into a phase of managing the final roll-out and transition to future prices. This stage will look at how to incentivise the take-up of future pricing by retailers / consumers, monitoring how consumers change their behaviour once they are subject to future pricing, and managing the reputational and political risk of the transition to future pricing.

8.2.3 Resources required

To implement pricing reform, Aurora will primarily use internal resources but will complement this with external consultants if, and when, required.

Aurora will also continue to contribute and participate in ENA pricing development working groups and forums.

8.3 Recovery of Interconnection Charges and Distributed Generation Allowance

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

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

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

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

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

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

Aurora acknowledges the recent decision by the Electricity Authority to shift the responsibility for determining distributed generation allowance from distributors to Transpower. The impact of the Authority's decisions is that, from 1 April 2018, payments to distributed generators will only be recovered from consumers if Transpower determines that the generator provides genuine grid support.

8.4 Transmission Pricing Methodology

The Electricity Authority continues to consult with interested persons in regard to proposed changes to the Transmission Pricing Methodology (TPM). The Authority released its second TPM issues paper in May 2016, and conducted supplementary consultation in December 2016.

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The Authority proposes that the existing interconnection and HVDC charges be replaced by an area-of-benefit (AoB) charge on relatively new transmission investments and a residual charge for costs not covered by other charges within the TPM. The Authority expects that, as a consequence of renewal investment, the AoB charge component will increase over time, and the residual charge decrease. The existing connection charge for assets that can be readily allocated to a grid customer will generally remain.

Like all proposal of this nature, the Authority's TPM proposal creates winners and losers. On average, the Authority predicts that Aurora's transmission charges will decline by around 5%, on average, with those savings ultimately being passed through to consumers in Aurora's prices.

The new TPM is not expected to come into effect before 1 April 2019.

8.5 Irrigation Contribution to Summer Peaking – Cromwell GXP

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

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

8.6 Small Scale Distributed Generation

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

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

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

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9 Cost Structure

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

9.1 Distribution Costs

Distribution costs derive from three cost drivers.

Asset Costs:

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

System Operation Costs:

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

Overhead Costs:

- c) 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 74% to 236%), as follows:

Grid Exit Point (GXP)	ORC ⁹	MW Peak ¹⁰	ORC / MW	
Clyde	\$102,240,499	17.1	\$5,982,475	236%
Cromwell	\$160,017,532	35.2	\$4,551,772	179%
Frankton	\$138,691,915	57.6	\$2,408,097	95%
Halfway Bush	\$222,315,319	118.5	\$1,876,930	74%
South Dunedin	\$125,052,367	66.6	\$1,876,617	74%
Totals	\$748,317,632	295.1	\$2,535,587 ¹¹	100%

Table 1 - Variation of asset \$ORC per MW

Optimised Depreciated Replacement Cost (ODRC) of assets has not been used in the above illustration because Optimised Replacement Cost (ORC) is less susceptible to significant variation when large zone substation and sub-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.

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 Weighted Average

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9.2 Pass-through Costs

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

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

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

Interconnection Charge:

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

Connection Charge:

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

The variation of these costs per MW of capacity provided for consumer use is significant between GXP (a range from 91% to 110%), as follows:

Grid Exit Point (GXP)	\$ / MW	% of average
Clyde	\$114,454	94%
Cromwell	\$110,378	91%
Frankton	\$133,458	110%
Halfway Bush	\$114,282	94%
South Dunedin	\$130,672	108%
Weighted Average	\$121,274	100%

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

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

9.3 Combined Pass-through and Distribution Costs

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

GXP Area	Pass-through Cost	Distribution Cost	Composite Cost	Price Zone
Weighting	37%	63%	100%	
Clyde	93%	236%	179%	CYD & CML
Cromwell	90%	179%	144%	
Frankton	107%	95%	100%	FKN
Halfway Bush	93%	74%	81%	HWB & SDN
South Dunedin	113%	74%	89%	
Weighted Average	100%	100%	100%	

Table 3 - Cost driver ratios

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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 35% of an average cost and can form a single geographical region, 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.

9.4 Revenue Requirements for Year Ended 31 March 2018¹²

Notional revenue		\$58.835 million
Pass-through costs		\$34.943 million
Transmission costs	\$27.911 million	
Distributed generation allowance	\$7.857 million	
Commerce Act levy	\$0.130 million	
Electricity Authority levy	\$0.256 million	
EGCC levy	\$0.052 million	
Local Authority rates	\$0.979 million	
2015 capital expenditure wash-up	(\$0.636 million)	
Reliability incentive	(\$0.565 million)	
Prior period Pass-through balance adjustment	(\$1.038 million)	
Estimated current year Pass-through balance	(\$0.002 million)	
Target revenue budgeted for 2017/18		\$93.778 million

This revenue requirement is derived from the four pricing areas:

	Distribution	Pass-through	Total
Dunedin HB & SDN area	\$29.519 million	\$22.168 million	\$51.687 million
Central CML & CYD area	\$19.103 million	\$5.416 million	\$24.519 million
Central FKN area	\$10.132 million	\$7.359 million	\$17.491 million
Heritage Estate	\$ 0.080 million		\$ 0.080 million
Total	\$58.835 million	\$34.943 million	\$93.778 million
Weighting	63%	37%	100%

Table 4 - Revenue requirement by pricing area

These regional cost recovery requirements are further allocated to (regional) load groups as Commerce Commission except for Aurora's 'Heritage Estate' embedded network at Te Anau, where the connection numbers (106) are so small that the breakdown by load group is less meaningful.

9.4.1 Underlying Drivers of the 2017 price change

The underlying drivers for the 2017 price change are increases in both distribution and pass-through costs. The changes are quantified in Table 5 below:

Cost Category	Change from 2016
Notional revenue	+\$1.811 million
Pass-through costs	+\$0.947 million

Table 5 - Price change drivers

¹² Derived in accordance with the Commerce Commission's Electricity Distribution Services Default Price-Quality Path Determination 2012.

9.5 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.

9.5.1 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.

9.5.2 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	\$37.6 million	11%	\$ 1.299 million
Zone substations	\$81.5 million	23%	\$ 7.917 million
High voltage lines	\$75.2 million	22%	\$ 6.228 million
Distribution substations	\$69.8 million	20%	\$ 9.261 million
Low voltage lines	\$83.2 million	24%	\$ 4.813 million
Total	\$347.4 million	100%	\$29.519 million

Table 6 - Dunedin pricing area costs by asset class

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

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

Group	kVA Range	Connections	Annual Energy Delivery (GWh)	Group Anytime Demand (MW)	Sum of Installed Capacity (MVA)	Group Control Period Demand (MW)
S/L	0	2	7.3	1.7	11.8	1.1
L1	0 – 15	51,356	402.4	119.4	760.4	97.5
L2	16 – 149	3,056	138.1	31.2	154.6	24.0
L3	150 – 499	198	84.7	19.2	49.3	14.8
L4	500 – 2,499	70	105.8	26.3	53.2	15.6
L5	2,500+	7	54.9	12.7	25.4	7.3
Total		54,689	793.1	210.4	1,054.7	160.2

Table 7 - Dunedin pricing area cost allocation statistics

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

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

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

Cost Category	SL	L1	L2	L3	L4	L5	W33	Total
33kV lines	9	692	175	108	131	62	122	1,299
Zone substations	59	4,655	1,181	726	878	419		7,917
High voltage lines	48	3,807	966	594	719	93		6,228
Distribution substations	121	6,472	1,652	1,016				9,261
Low voltage lines	48	3,762	955	48				4,813
Total	284	19,388	4,929	2,491	1,728	574	122	29,519

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

Cost Category	SL	L1	L2	L3	L4	L5	W33	Total
Pass-through	152	14,100	3,207	1,849	1,947	914		22,168

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

9.5.3 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	\$31.7 million	12%	\$1.285 million
Zone substations	\$26.9 million	10%	\$2.964 million
High voltage lines	\$87.9 million	33%	\$8.566 million
Distribution substations	\$53.5 million	20%	\$4.043 million
Low voltage lines	\$62.3 million	24%	\$2.244 million
Total	\$262.3 million	100%	\$19.103 million

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

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

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

Group	kVA Range	Connections	Annual Energy Delivery (GWh)	Group Anytime Demand (MW)	Sum of Installed Capacity (MVA)	Group Control Period Demand (MW)
S/L	0	5	1.9	0.4	2.9	0.3
L1	0 – 15	17,506	113.1	43.2	254.1	35.2
L2	16 – 149	1,681	70.7	13.1	86.8	9.6
L3	150 – 499	124	36.7	7.3	27.9	3.8
L4	500 – 2,499	26	22.6	7.4	17.5	2.9
L5	2,500+	1	6.6	1.3	2.5	0.0
Total		19,343	251.6	72.7	391.7	51.7

Table 11 - Clyde / Cromwell pricing area cost allocation statistics

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

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

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

Cost Category	SL	L1	L2	L3	L4	L5	P33	Total
66kV/33kV lines	5	548	157	75	67	8	426	1,285
Zone substations	16	1,889	542	258	232	28		2,964
High voltage lines	47	5,507	1,580	753	679			8,566
Distribution substations	39	2,806	811	388				4,043
Low voltage lines	14	1,679	483	67				2,244
Total	120	12,429	3,573	1,541	978	35	426	19,103

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

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Cost Category	SL	L1	L2	L3	L4	L5	P33	Total
Pass-through	27	3,709	995	389	289	6		5,416

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

9.5.4 Frankton Area Cost Allocations

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

Total Asset Costs by Asset Class	ORC \$	ORC %	Allocated Revenue
33kV lines	\$9.1 million	7%	\$0.370 million
Zone substations	\$22.0 million	16%	\$1.924 million
High voltage lines	\$38.0 million	27%	\$4.108 million
Distribution substations	\$29.4 million	21%	\$2.179 million
Low voltage lines	\$40.3 million	29%	\$1.553 million
Total	\$138.7 million	100%	\$10.134 million

Table 14 - Frankton pricing area distribution costs by asset class

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

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

Group	kVA Range	Connections	Annual Energy Delivery (GWh)	Group Anytime Demand (MW)	Sum of Installed Capacity (MVA)	Group Control Period Demand (MW)
S/L	0	3	1.1	0.3	1.8	0.2
L1	0 – 15	11,487	102.4	37.6	166.9	32.6
L2	16 – 149	1,446	63.8	13.3	68.9	11.7
L3	150 – 499	62	20.7	5.4	15.3	4.0
L4	500 – 2,499	25	38.3	8.3	17.5	6.3
L5	2,500+	1	5.6	2.1	5.0	1.8
Total		13,024	231.9	67.1	275.3	56.4

Table 15 - Frankton pricing area cost allocation statistics

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

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

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

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Cost Category	SL	L1	L2	L3	L4	L5	P33	Total
33kV lines	1	191	68	26	40	11	34	370
Zone substations	6	1,094	389	146	227	61		1,924
High voltage lines	14	2,402	855	321	497	19		4,108
Distribution substations	19	1,446	518	195				2,179
Low voltage lines	7	1,106	394	47				1,553
Total	47	6,240	2,224	735	763	91	34	10,134

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

Cost Category	SL	L1	L2	L3	L4	L5	P33	Total
Pass-through	27	4,328	1,582	490	728	207		7,361

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

10 Customer Connection Definitions

10.1 Residential Connection Definition

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

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

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

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

If there is a likelihood of injection of energy from the connection, then two-way import/ export metering must be installed to remain on the Residential volumetric price.

In addition to the above criteria, Aurora applies Residential pricing to ICPs in the following situations:

10.1.1 Potable Water Supplies for Residential Connections

Where consumers can demonstrate that a stand-alone connection supplying a water pump provides potable water to an existing Residential connection, and that Residential connection only, then the connection to the water pump will qualify for Residential pricing.

The potable water option only applies on the Central Otago network, and to qualify the potable water connection should not be subject to inconsistent network load control (e.g., irrigation control).

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10.1.2 High Capacity Residential Connections with Annual Consumption less than 9,000kWh

There are high capacity connections (greater than 15kVA) on the Aurora network that are a consumer's primary residence. These connections do not normally qualify for Residential pricing, as Residential pricing typically only applies to 15kVA or 8kVA connections. However, the current interpretation of the LFC regulations requires Aurora to offer LFC compliant pricing to low-use primary residences, irrespective of the capacity of the connection.

To comply with this requirement, Aurora allows Residential pricing to apply to any primary residence with an installed capacity greater than 15kVA, provided that the most recent 12 months of submitted consumption is 9,000kWh or less. Transfer to Residential pricing will be assessed by Aurora upon a request received from a retailer or consumer.

10.1.3 Temporary Connections Where the Consumer is Living On-site

Aurora allows consumers that are living on-site during the construction of their primary residence to be placed on Residential pricing. The consumer may be living in a caravan, shed, or other type of temporary accommodation.

10.2 General Connection Definition

General connections are all connections that are not Residential connections as defined in section 10.1.

11 Pricing Components

11.1 Distribution Cost Recovery Components

11.1.1 Residential Distribution Price Components

Two components of delivery prices are used and the pricing details are outlined in Schedules A to E (A1, B1, C1, D1, E1). The components are as follows:

11.1.1.1 Fixed Component

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

11.1.1.2 Volumetric Component

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

In the Dunedin area, most residential connections have a single meter, which records both uncontrolled and controlled (water heating with minimum 16 hours service) consumption.

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

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

11.1.1.3 Closure of Dunedin All-Inclusive price options

As mentioned in section 6.1, Aurora has closed the All-Inclusive price option to new consumers in Dunedin.

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The single meter arrangement was put in place, historically, because the cost of providing separate metering to measure uncontrolled and controlled consumption was deemed greater than the benefit. However, with the advent of modern electronic meters, the marginal cost of using a dual register meter to log consumption information for uncontrolled and controlled loads is minimal.

In deriving the all-inclusive price, there is an assumption made as to the relative proportions of uncontrolled and controlled load. However, in practice, individual consumers will have higher and lower proportions of controlled and uncontrolled load to that assumed.

In addition, the all-inclusive price option creates a higher price signal for controlled hot water load than an uncontrolled/controlled dual price approach. This may encourage more hot water energy substitution (such as LPG, solid fuel, or solar hot water supplies), than is economically efficient. Consumers that remove electric hot water cylinders should transfer to an uncontrolled supply; however, the installation of water heating energy substitutes is not managed by Aurora or its approved contractors, and therefore is difficult to monitor.

Consumers connected prior to 1 April 2017 will remain eligible for the all-inclusive price option.

11.1.2 General Distribution Price Components

Up to five components of delivery prices are used and the pricing details are outlined in Schedules A to E (A2, B2, C2, D2, E2). The components are as follows:

11.1.2.1 Fixed price

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

11.1.2.2 Capacity Price

- Connections metered at low voltage

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

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

- Connections metered at high voltage

This price recovers costs associated with the distribution system local to each connection point; i.e., high voltage 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 high voltage metered connections is approximately the same as for low voltage metered connections in Load Groups 4 and 5. See also section 9.1.

11.1.2.3 Distance Price

For the L3, L3A, L4 and L5 load groups (assessed capacity 150 kVA or greater), the costs associated with high voltage lines and cables and sub-transmission lines and cables are recovered by a kVA-km price. 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.

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This price 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, distribution alternatives may be more appropriate and this component signals this fact.

11.1.2.4 Control Period Demand Price

The Control Period Demand (CPD) price recovers costs associated with zone substations and sub-transmission lines and cables, which are sized for system peak loads.

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

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

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

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

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

11.1.2.5 Equipment Charge

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

11.2 Pass-through Cost Recovery Components

11.2.1 Residential Connections

For Residential connections in load groups L1A (≤ 8 kVA) and L1 (≤ 15 kVA), the pass-through costs are recovered by a volumetric (cents/kWh) price.

11.2.2 General Connections

For the General L1A (≤ 8 kVA), L1 (≤ 15 kVA), L2 (16-149 kVA), L3 (150-249 kVA), L3A (250-499 kVA), L4 (500-2499 kVA) and L5 (2500+ kVA) load groups, all allocated pass-through costs excluding the

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transmission interconnection charge and distributed generation allowance are recovered by way of an assessed capacity price (\$ per installed kVA). Allocated transmission interconnection charges and the allocated distributed generation allowance are recovered by way of a CPD price (\$ per kW).

11.2.3 Loss and Constraint Excess Payments

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

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

As mentioned in Section 5.1 Aurora consulted with retailers in 2016 regarding ceasing the direct pass-through of Loss and Constraint Excess Payments. Aurora saw benefits in the proposal, in that it would reduce the amount of total recoverable costs and, consequently, reduce the pass-through price and total delivery prices retailers would otherwise be charged. However Aurora received conflicting feedback to this proposal, and will consider this matter further in 2017.

11.3 Target Revenue by Price Component

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

	Price Component	Dunedin	Clyde and Cromwell	Frankton	Heritage Estate	Total
Distribution (\$'000's)	Fixed	\$2,905	\$1,078	\$820	\$6	\$4,809
	Volumetric	\$15,410	\$10,302	\$5,148	\$68	\$30,928
	Capacity	\$5,560	\$3,710	\$2,267	\$2	\$11,539
	kVA-km	\$215	\$565	\$106		\$886
	CPD	\$4,965	\$2,873	\$1,712	\$2	\$9,552
	Equipment	\$56	\$24			\$80
	Street lighting	\$284	\$123	\$46	\$3	\$457
	Generation	\$123	\$427	\$34		\$584
	<i>Subtotal</i>	<i>\$29,519</i>	<i>\$19,104</i>	<i>\$10,132</i>	<i>\$80</i>	<i>\$58,835</i>
Pass-through (\$'000's)	Fixed	\$36	\$74	\$262		\$373
	Volumetric	\$12,618	\$3,141	\$3,747		\$19,505
	Capacity	\$1,743	\$179	\$1,046		\$2,968
	CPD	\$7,622	\$1,989	\$2,278		\$11,889
	Street lighting	\$149	\$33	\$27		\$208
	<i>Subtotal</i>	<i>\$22,168</i>	<i>\$5,416</i>	<i>\$7,359</i>		<i>\$34,943</i>
Total		\$51,687	\$24,520	\$17,491	\$80	\$93,778

Table 18 - Target Revenue by Price Component

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12 Seasonal Loads

12.1 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 delivery charges over the winter period.

Aurora has considered the option of having seasonal prices. However, in the interests of maintaining as few prices 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.

12.2 Delivery Pricing Recovery

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

12.3 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 delivery 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 delivery 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.

13 Other Pricing Considerations

Other considerations relevant to Aurora's pricing methodology are:

- a) Prices 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) Prices for load group 4 (500 to 2499 kVA) and load group 5 (2500+ kVA) have been calculated on the basis that they are all high voltage metered installations; an additional charge will apply where Aurora owns the transformers and associated high voltage switchgear.
- d) Prices 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) Prices exclude metering services involved with the provision of meters or meter reading. These services are provided by others.

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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)
- High voltage lines and cables (11 kV and 6.6 kV)
- Distribution substations (11/6.6 kV to 400 V transformation)
- Low voltage 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.

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

14 Non-standard Contracts

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

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

Aurora has two operative non-standard agreements, covering 9 ICPs. Aurora expects to generate approximately 0.45% of target revenue (\$418,747) from these ICPs in the year to 31 March 2018.

15 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 delivery prices apply according to the installation connection capacity.

15.1 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

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- c) Avoided Transmission Charges¹³ 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 delivery prices apply according to the installation's connection capacity. Owners of small-scale distributed generation that forms part of a residential connection are able to avoid the full retail costs of energy (per unit), including the delivery price components.

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

15.2 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.

15.2.1 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 sub-transmission network (33kV and 66kV); however injection into Aurora's 11kV distribution network may be possible.

Where generation specific sub-transmission 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 sub-transmission 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 sub-transmission 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

¹³ Referred to in sections 1 to 8 as the Distributed Generation Allowance in accordance with regulatory terminology; however, in this section we have maintained the term Avoided Transmission as this more accurately conveys the basis of the charge to interested persons.

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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.

15.2.2 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:

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

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.

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

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

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

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.

¹⁴ In the case of sub-transmission lines, Aurora may use a reasonable estimate of the proportion of pole types (concrete or wood) to calculate a composite asset life.

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15.2.4 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.

15.3 Connection Charge Adjustments

15.3.1 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.

15.3.2 Valuation Review

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

15.4 Transmission Related Transactions

15.4.1 Avoided Cost of Transmission (Interconnection) Payments

Distributed Generation reduces Aurora's off-take requirements at Grid Exit Points (GXP's). 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

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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 Cost of Transmission (ACOT) 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 ACOT paid to each Distributed Generator is based upon:

$$\text{ACOT (Gen)} = \text{Avoided Transmission Demand} \times \text{ATR} \times \text{IC}$$

where:

ATR is the Avoided Transmission Rate according to Table 19.

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.

As discussed in section 8.3, the Electricity Authority has regulated the manner in which ACOT payments are made to distributed generators. From 1 April 2018 the eligibility and scale of ACOT payments will be determined by Transpower. Accordingly, this section will be modified at the next issue of the pricing methodology.

15.4.2 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.

As a result of the operational review of the Transmission Pricing Methodology in 2016, Transpower is in the process of transitioning the basis for allocating HVDC charges from Historic Anytime Maximum Injection (HAMI) to South Island Mean Injection (SIMI). This year, the relative weightings for the allocators are 75/25 percent.

Transpower sets the HAMI portion of the HVDC Charges for each GXP serving the Aurora network, by multiplying its HAMI Rate (\$/kW) by the HAMI recorded at the GXP. HAMI is defined as the higher of:

- 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
- The average of the 12 highest injections recorded at the GXP during any of the four immediately preceding pricing years.

Transpower sets the SIMI portion of the HVDC Charges, by multiplying its SIMI Rate (\$/MWh) by the SIMI recorded at the GXP. SIMI is defined as the average energy injection reported by Transpower during the assessment period.

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15.5 Current Prices

Generator	Generation Details		Prices (\$ per annum)		
	GXP	Capacity (MW) ¹⁵	Connection	AVC	HVDC
Generator 1	HWB	123.1	\$123,339	\$5,691,060	\$620,010
Generator 2	CYD	22.2	\$337,116	\$1,487,092	\$389,980
Generator 2	CML	4.3	\$64,402	\$385,044	\$-
Generator 2	FKN	2.2	\$33,538	\$185,661	\$-
Generator 3	CYD	2.2	\$25,978	\$108,004	\$50,464

Table 20 - Distributed generation prices

16 References

Electricity Authority	Electricity Industry Participation Code
Commerce Commission	Electricity Distribution Information Disclosure Determination 2012.
Commerce Commission	Electricity Distribution Services Default Price-Quality Path Determination 2015.
AE-S014	Network connection Standard

¹⁵ Nameplate rating.

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Schedule A – Prices – South Dunedin & Halfway Bush GXP

A1. Residential Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Daily Price Component					
Daily Fixed Price (≤15kVA)	SHSD15	15.00		15.00	¢/day
Daily Fixed Price (≤8kVA)	SHSD8	4.10		4.10	¢/day
Volumetric Price Component					
Uncontrolled - Summer	010	6.17	2.54	8.71	¢/kWh
Uncontrolled - Winter	010	6.80	6.25	13.05	¢/kWh
All Inclusive - Summer ¹⁶	017	2.98	2.46	5.44	¢/kWh
All Inclusive - Winter ¹⁶	017	4.42	3.74	8.16	¢/kWh
Controlled	006	1.90	1.16	3.06	¢/kWh
Night Boost	024	1.55	0.80	2.35	¢/kWh
Night Only	028	0.42		0.42	¢/kWh
All Inclusive - Summer Day ¹⁶	011	5.64	2.50	8.14	¢/kWh
All Inclusive - Winter Day ¹⁶	011	5.84	6.48	12.32	¢/kWh
All Inclusive - Summer Night ¹⁶	012	0.42		0.42	¢/kWh
All Inclusive - Winter Night ¹⁶	012	0.42		0.42	¢/kWh
A2. General Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Street Lighting Price Components					
Daily Fixed Price (SDN)	SDNSTL	262.12	137.32	399.44	\$/ICP/day
Daily Fixed Price (HWP)	HWBSTL	514.72	269.65	784.37	\$/ICP/day
Distributed Unmetered Load (DUML) Price Components					
Daily Fixed Price	SHSUNM	3.92		3.92	¢/ICP/day
Volumetric Price	030	1.39	2.13	3.52	¢/kWh
Load Group 0 (Unmetered Supply <1kVA Capacity) Price Components					
Daily Fixed Price	SH0	31.93	25.72	57.65	¢/day
Load Group 0A (Temporary Connection) Price Components					
Daily Fixed Price	SH0A	66.28	55.55	121.83	¢/day
Load Group 1A (≤8kVA Capacity) Price Components					
Daily Fixed Price	SH1A	2.96		2.96	¢/day
Capacity Price	SH1A	4.07	2.95	7.02	¢/kVA/day
CPD Price	SH1A	25.36	31.38	56.74	¢/kW/day
A2. General Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Load Group 1 (≤15kVA Capacity) Price Components					
Daily Fixed Price	SH1	2.96		2.96	¢/day
Capacity Price	SH1	3.64	2.55	6.19	¢/kVA/day
CPD Price	SH1	25.36	31.38	56.74	¢/kW/day
Load Group 2 (16-149kVA Capacity) Price Components					
Daily Fixed Price	SH2	6.40		6.40	¢/day
Capacity Price	SH2	4.63	0.69	5.32	¢/kVA/day
CPD Price	SH2	25.36	31.38	56.74	¢/kW/day
Load Group 3 (150-249kVA Capacity) Price Components					
Daily Fixed Price	SH3	116.00		116.00	¢/day
Capacity Price	SH3	7.64	1.62	9.26	¢/kVA/day
Distance Price	SH3	0.08		0.08	¢/kVA-km/day
CPD Price	SH3	17.31	28.27	45.58	¢/kW/day
Load Group 3A (250-499kVA Capacity) Price Components					
Daily Fixed Price	SH3A	116.00		116.00	¢/day
Capacity Price	SH3A	7.03	1.62	8.65	¢/kVA/day
Distance Price	SH3A	0.08		0.08	¢/kVA-km/day
CPD Price	SH3A	17.31	28.27	45.58	¢/kW/day
Load Group 4 (500-2,499kVA Capacity) Price Components					
Daily Fixed Price	SH4	293.00		293.00	¢/day
Capacity Price	SH4	3.75	2.23	5.98	¢/kVA/day
Distance Price	SH4	0.08		0.08	¢/kVA-km/day
CPD Price	SH4	14.62	28.27	42.89	¢/kW/day
Equipment Price (if applicable)	SH4	70.00		70.00	¢/kVA/mth
Load Group 5 (2,500kVA+ Capacity) Price Components					
Daily Fixed Price	SH5	293.00		293.00	¢/day
Capacity Price	SH5	2.50	1.48	3.98	¢/kVA/day
Distance Price	SH5	0.08		0.08	¢/kVA-km/day
CPD Price	SH5	9.16	28.27	37.43	¢/kW/day
Equipment Price (if applicable)	SH5	70.00		70.00	¢/kVA/mth

¹⁶ Price option closed to new connections – see note 16 (Schedule F)

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Schedule B – Prices – Clyde & Cromwell GXP

B1. Residential Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Daily Price Component					
Daily Fixed Price (≤15kVA)	CCSD15	15.00		15.00	£/day
Daily Fixed Price (≤8kVA)	CCSD8	4.10		4.10	£/day
Volumetric Price Component					
Uncontrolled - Summer	101	10.18	2.17	12.35	£/kWh
Uncontrolled - Winter	101	13.68	4.92	18.60	£/kWh
Controlled (20hr)	109	7.32	2.62	9.94	£/kWh
Controlled (16hr)	106	5.29	1.54	6.83	£/kWh
Night Boost (13hr)	103	5.96	2.21	8.17	£/kWh
Night Boost (11hr)	104	4.88	1.17	6.05	£/kWh
Night Only	108	4.18		4.18	£/kWh
B2. General Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Street Lighting Price Components					
Daily Fixed Price	CCSTL	3.72		3.72	£/lamp/day
Volumetric Price	110	3.98	1.60	5.58	£/kWh
Load Group 0 (Unmetered Supply <1kVA Capacity) Price Components					
Daily Fixed Price	CC0	52.17	19.32	71.49	£/day
Load Group 0A (Temporary Connection) Price Components					
Daily Fixed Price	CC0A	99.47	48.63	148.10	£/day
Load Group 1A (≤8kVA Capacity) Price Components					
Daily Fixed Price	CC1A	3.67		3.67	£/day
Capacity Price	CC1A	8.10	1.04	9.14	£/kVA/day
CPD Price	CC1A	46.43	29.46	75.89	£/kW/day
Load Group 1 (≤15kVA Capacity) Price Components					
Daily Fixed Price	CC1	3.67		3.67	£/day
Capacity Price	CC1	7.48	0.68	8.16	£/kVA/day
CPD Price	CC1	46.43	29.46	75.89	£/kW/day
B2. General Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Load Group 2 (16-149kVA Capacity) Price Components					
Daily Fixed Price	CC2	7.71		7.71	£/day
Capacity Price	CC2	6.32	0.17	6.49	£/kVA/day
CPD Price	CC2	40.05	25.83	65.88	£/kW/day
Load Group 3 (150-249kVA Capacity) Price Components					
Daily Fixed Price	CC3	148.00		148.00	£/day
Capacity Price	CC3	7.53	0.27	7.80	£/kVA/day
Distance Price	CC3	0.10		0.10	£/kVA-km/day
CPD Price	CC3	43.16	25.08	68.24	£/kW/day
Load Group 3A (250-499kVA Capacity) Price Components					
Daily Fixed Price	CC3A	148.00		148.00	£/day
Capacity Price	CC3A	6.68	0.27	6.95	£/kVA/day
Distance Price	CC3A	0.10		0.10	£/kVA-km/day
CPD Price	CC3A	43.16	25.08	68.24	£/kW/day
Load Group 4 (500-2,499kVA Capacity) Price Components					
Daily Fixed Price	CC4	387.00		387.00	£/day
Capacity Price	CC4	5.44	0.18	5.62	£/kVA/day
Distance Price	CC4	0.10		0.10	£/kVA-km/day
CPD Price	CC4	38.53	25.08	63.61	£/kW/day
Equipment Price (if applicable)	CC4	70.00		70.00	£/kVA/mth
Load Group 5 (2,500kVA+ Capacity) Price Components					
Daily Fixed Price	CC5	387.00		387.00	£/day
Capacity Price	CC5	4.80	0.18	4.98	£/kVA/day
Distance Price	CC5	0.10		0.10	£/kVA-km/day
CPD Price	CC5	38.53	25.08	63.61	£/kW/day
Equipment Price (if applicable)	CC5	70.00		70.00	£/kVA/mth

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Schedule C – Prices – Frankton GXP

C1. Residential Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Daily Price Component					
Daily Fixed Price (≤15kVA)	FRSD15	15.00		15.00	£/day
Daily Fixed Price (≤8kVA)	FRSD8	4.10		4.10	£/day
Volumetric Price Component					
Uncontrolled - Summer	201	6.52	2.88	9.40	£/kWh
Uncontrolled - Winter	201	7.77	6.39	14.16	£/kWh
Controlled (20hr)	209	3.71	2.76	6.47	£/kWh
Controlled (16hr)	206	1.65	1.93	3.58	£/kWh
Night Boost (13hr)	203	2.42	2.42	4.84	£/kWh
Night Boost (11hr)	204	1.48	1.26	2.74	£/kWh
Night Only	208	1.06		1.06	£/kWh
C2. General Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Street Lighting Price Components					
Daily Fixed Price	FRSTL	3.72		3.72	£/lamp/day
Volumetric Price	210	0.96	2.29	3.25	£/kWh
Load Group 0 (Unmetered Supply <1kVA Capacity) Price Components					
Daily Fixed Price	FR0	32.50	23.78	56.28	£/day
Load Group 0A (Temporary Connection) Price Components					
Daily Fixed Price	FR0A	58.89	53.86	112.75	£/day
Load Group 1A (≤8kVA Capacity) Price Components					
Daily Fixed Price	FR1A	3.06		3.06	£/day
Capacity Price	FR1A	4.09	4.09	8.18	£/kVA/day
CPD Price	FR1A	19.25	28.97	48.22	£/kW/day
Load Group 1 (≤15kVA Capacity) Price Components					
Daily Fixed Price	FR1	3.06		3.06	£/day
Capacity Price	FR1	3.83	3.89	7.72	£/kVA/day
CPD Price	FR1	19.25	28.97	48.22	£/kW/day
C2. General Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Load Group 2 (16-149kVA Capacity) Price Components					
Daily Fixed Price	FR2	4.97		4.97	£/day
Capacity Price	FR2	4.80	1.56	6.36	£/kVA/day
CPD Price	FR2	23.80	26.18	49.98	£/kW/day
Load Group 3 (150-249kVA Capacity) Price Components					
Daily Fixed Price	FR3	113.00		113.00	£/day
Capacity Price	FR3	11.05	2.62	13.67	£/kVA/day
Distance Price	FR3	0.09		0.09	£/kVA-km/day
CPD Price	FR3	14.97	21.33	36.30	£/kW/day
Load Group 3A (250-499kVA Capacity) Price Components					
Daily Fixed Price	FR3A	113.00		113.00	£/day
Capacity Price	FR3A	10.11	2.62	12.73	£/kVA/day
Distance Price	FR3A	0.09		0.09	£/kVA-km/day
CPD Price	FR3A	14.97	21.33	36.30	£/kW/day
Load Group 4 (500-2,499kVA Capacity) Price Components					
Daily Fixed Price	FR4	297.00		297.00	£/day
Capacity Price	FR4	5.50	4.25	9.75	£/kVA/day
Distance Price	FR4	0.09		0.09	£/kVA-km/day
CPD Price	FR4	17.27	21.33	38.60	£/kW/day
Equipment Price (if applicable)	FR4	70.00		70.00	£/kVA/mth
Load Group 5 (2,500kVA+ Capacity) Price Components					
Daily Fixed Price	FR5	297.00		297.00	£/day
Capacity Price	FR5	1.31	4.94	6.25	£/kVA/day
Distance Price	FR5	0.09		0.09	£/kVA-km/day
CPD Price	FR5	11.88	21.33	33.21	£/kW/day
Equipment Price (if applicable)	FR5	70.00		70.00	£/kVA/mth

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Schedule D – Prices – Frankton GXP (sub-area)

D1. Residential Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Daily Price Component					
Daily Fixed Price (≤15kVA)	FKSD15	15.00		15.00	£/day
Daily Fixed Price (≤8kVA)	FKSD8	4.10		4.10	£/day
Volumetric Price Component					
Uncontrolled - Summer	301	6.52	2.88	9.40	£/kWh
Uncontrolled - Winter	301	7.77	6.39	14.16	£/kWh
Controlled (20hr)	309	3.71	2.76	6.47	£/kWh
Controlled (16hr)	306	1.65	1.93	3.58	£/kWh
Night Boost (13hr)	303	2.42	2.42	4.84	£/kWh
Night Boost (11hr)	304	1.48	1.26	2.74	£/kWh
Night Only	308	1.06		1.06	£/kWh
D2. General Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Street Lighting Price Components					
Daily Fixed Price	FKSTL	3.72		3.72	£/lamp/day
Volumetric Price	310	0.96	2.29	3.25	£/kWh
Load Group 0 (Unmetered Supply <1kVA Capacity) Price Components					
Daily Fixed Price	FK0	32.50	23.78	56.28	£/day
Load Group 0A (Temporary Connection) Price Components					
Daily Fixed Price	FK0A	58.89	53.86	112.75	£/day
Load Group 1A (≤8kVA Capacity) Price Components					
Daily Fixed Price	FK1A	3.06		3.06	£/day
Capacity Price	FK1A	4.09	4.09	8.18	£/kVA/day
CPD Price	FK1A	19.25	28.97	48.22	£/kW/day
Load Group 1 (≤15kVA Capacity) Price Components					
Daily Fixed Price	FK1	3.06		3.06	£/day
Capacity Price	FK1	3.83	3.89	7.72	£/kVA/day
CPD Price	FK1	19.25	28.97	48.22	£/kW/day

D2. General Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Load Group 2 (16-149kVA Capacity) Price Components					
Daily Fixed Price	FK2	4.47		4.47	£/day
Capacity Price	FK2	4.32	1.56	5.88	£/kVA/day
CPD Price	FK2	21.42	26.18	47.60	£/kW/day
Load Group 3 (150-249kVA Capacity) Price Components					
Daily Fixed Price	FK3	93.00		93.00	£/day
Capacity Price	FK3	9.12	2.62	11.74	£/kVA/day
Distance Price	FK3	0.09		0.09	£/kVA-km/day
CPD Price	FK3	12.35	21.33	33.68	£/kW/day
Load Group 3A (250-499kVA Capacity) Price Components					
Daily Fixed Price	FK3A	93.00		93.00	£/day
Capacity Price	FK3A	8.34	2.62	10.96	£/kVA/day
Distance Price	FK3A	0.09		0.09	£/kVA-km/day
CPD Price	FK3A	12.35	21.33	33.68	£/kW/day
Load Group 4 (500-2,499kVA Capacity) Price Components					
Daily Fixed Price	FK4	230.00		230.00	£/day
Capacity Price	FK4	4.26	4.25	8.51	£/kVA/day
Distance Price	FK4	0.09		0.09	£/kVA-km/day
CPD Price	FK4	13.38	21.33	34.71	£/kW/day
Equipment Price (if applicable)	FK4	70.00		70.00	£/kVA/mth
Load Group 5 (2,500kVA+ Capacity) Price Components					
Daily Fixed Price	FK5	230.00		230.00	£/day
Capacity Price	FK5	1.02	4.94	5.96	£/kVA/day
Distance Price	FK5	0.09		0.09	£/kVA-km/day
CPD Price	FK5	9.21	21.33	30.54	£/kW/day
Equipment Price (if applicable)	FK5	70.00		70.00	£/kVA/mth

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Schedule E – Prices – Heritage Estate Embedded Subdivision, Te Anau

E1. Residential Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Daily Price Component					
Daily Fixed Price (≤15kVA)	HESD15	15.00		15.00	£/day
Daily Fixed Price (≤8kVA)	HESD8	4.10		4.10	£/day
Volumetric Price Component					
Uncontrolled - Summer	401	10.38		10.38	£/kWh
Uncontrolled - Winter	401	15.62		15.62	£/kWh
Controlled	406	4.86		4.86	£/kWh
Night Boost	404	4.30		4.30	£/kWh
Night Only	408	2.87		2.87	£/kWh
E2. General Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Street Lighting Price Components					
Daily Fixed Price	HESTL	3.72		3.72	£/lamp/day
Volumetric Price	410	6.71		6.71	£/kWh
Load Group 0 (Unmetered Supply <1kVA Capacity) Price Components					
Daily Fixed Price	HE0	59.15		59.15	£/day
Load Group 0A (Temporary Connection) Price Components					
Daily Fixed Price	HE0A	122.16		122.16	£/day
Load Group 1A (≤8kVA Capacity) Price Components					
Daily Fixed Price	HE1A	2.96		2.96	£/day
Capacity Price	HE1A	7.44		7.44	£/kVA/day
CPD Price	HE1A	64.81		64.81	£/kW/day
Load Group 1 (≤15kVA Capacity) Price Components					
Daily Fixed Price	HE1	2.96		2.96	£/day
Capacity Price	HE1	6.65		6.65	£/kVA/day
CPD Price	HE1	64.81		64.81	£/kW/day

E2. General Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Load Group 2 (16-149kVA Capacity) Price Components					
Daily Fixed Price	HE2	6.22		6.22	£/day
Capacity Price	HE2	6.24		6.24	£/kVA/day
CPD Price	HE2	62.63		62.63	£/kW/day

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Schedule F - Notes to Price Schedules

1. All prices are exclusive of GST.
2. Volumetric prices apply to kWh as metered at each ICP. The hours of service for controlled 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 Residential Consumers) Regulations 2004, then Residential pricing is available as an option.
9. For L4 and L5 load groups an additional \$8.40 per kVA of capacity applies if Aurora owns the distribution transformer.
10. An additional \$85.20 per kVAr per annum of equivalent corrective capacitance applies if the installation power factor is required to be improved to 0.95.
11. Loss Rental Rebates are excluded from pass-through prices 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 delivery prices.
14. For dual register meters that measure day and night consumption separately, day volumetric prices apply to consumption recorded between 7am and 11pm, and night volumetric prices 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.
16. The All Inclusive volumetric price options (codes "017", "011", and "012") on the South Dunedin and Halfway Bush GXPs are not available to ICPs with an Initial Energisation Date of 1 April 2017, or any later date.

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Schedule G – Register Discount Rates for Assessed CPD kW Calculation

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

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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 6.1
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 11
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 6.3 to 6.5
State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies	Clause 2.4.3 (3)	Section 9.4
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 9.4
State the consumer groups for whom prices have been set, and describe-		
(a) the rationale for grouping consumers in this way;		
(b) the method and the criteria used by the EDB to allocate consumers to each of the consumer groups	Clause 2.4.3 (5)	Sections 9.5 & 10
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 9.4.1

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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 11
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 11.3
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 8
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 8
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 8
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 14
how the EDB determines whether to use a non-standard contract, including any criteria used	Clause 2.4.5 (1) (b)	Section 14
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 14

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Information Disclosure Requirement	Determination Reference	Price Methodology Reference
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 14
any implications of this approach for determining prices for consumers subject to non-standard contracts	Clause 2.4.5 (2) (b)	Section 14
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 15.2
prices; and	Clause 2.4.5 (3) (a)	Section 15.5
value, structure and rationale for any payments to the owner of the distributed generation.	Clause 2.4.5 (3) (b)	Section 15.4

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Schedule I – Future Pricing Roadmap

Future Pricing Roadmap Checklist

EDB :

Aurora Energy Limited

Roadmap Stages		Timeline												
		2017 H1	2017 H2	2018 H1	2018 H2	2019 H1	2019 H2	2020	2021	2022	2023	2024	2025	
1. Initiate pricing reform														
Communicate	Prepare and publish future pricing roadmap, include reasoning and and why it's important	X												
Problem Identification & Discovery	Justification and early modelling			X										
Define overall objectives for reform	Set overall goals including target dates or date ranges			X										
Develop strategy to deliver reform	Develop ideas on how to go ahead (including long list of future pricing options if available)			X										
Identify challenges	eg, resourcing implications, billing systems, EIEP1 file formats, AMI penetration and technology, accessing data			X										
Establish high level plan	Gain commitment to reform, agree plan, allocate resources					X								
Consult retailers	Socialise ideas & plans with retailers					X								
Gather basic data for analytics	What do we need to know to progress reform? (eg. AMI penetration? Moving from GXP to ICP billing? Survey customers)						X							
Define pathway	Prepare final strategic pricing plan (including target dates)							X						
Alignment across EDBs	Compare plan with other EDB's, form coalitions							X						
2. Regulatory enablers														
Form of price control	Change in form of price control from Weighted Average Price Cap to Revenue Cap							X						
3. Plan changes in more detail														
Develop detailed plans, including:	Identify issues/prepare detailed pricing reform plans													
- regulatory compliance	Check plan meets regulatory expectations								X					
- data analysis to assess customer impacts	Narrow down preferred options and test market impacts								X					
- implementation and transition arrangements	Identify what will drive success								X					
- feedback loops and issues resolution	Develop processes to account for stakeholder views and review against target dates. Participate in ENA processes to provide stakeholders with single point of contact								X					
- communication	Educate customers and retailers about change									X				
4. Manage roll out of new pricing options														
Develop transition strategies	Incentivise and manage take-up over time for retailers and customers									X				
Adopt risk management approach	Identify and manage risks to markets, customers, EDBs (eg political and financial risks)										X			
Review progress and make adjustments	Actively consider progress towards outcomes over time											X		
Ongoing customer interactions	Monitor customer responses and manage as required											X		

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