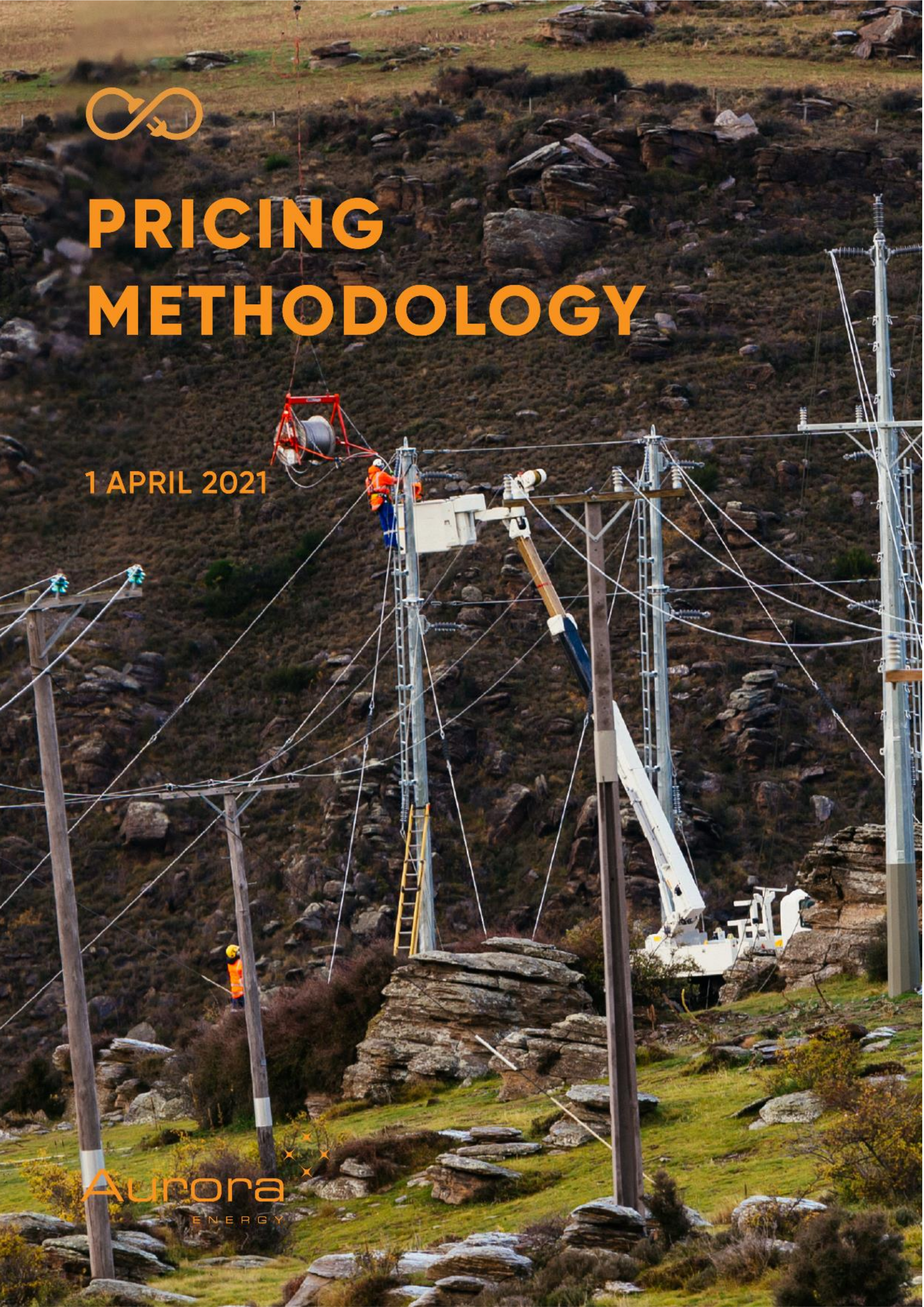
PRICING METHODOLOGY

1 APRIL 2021



Aurora
ENERGY

Table of Contents

1. Introduction

1.1. Preliminary

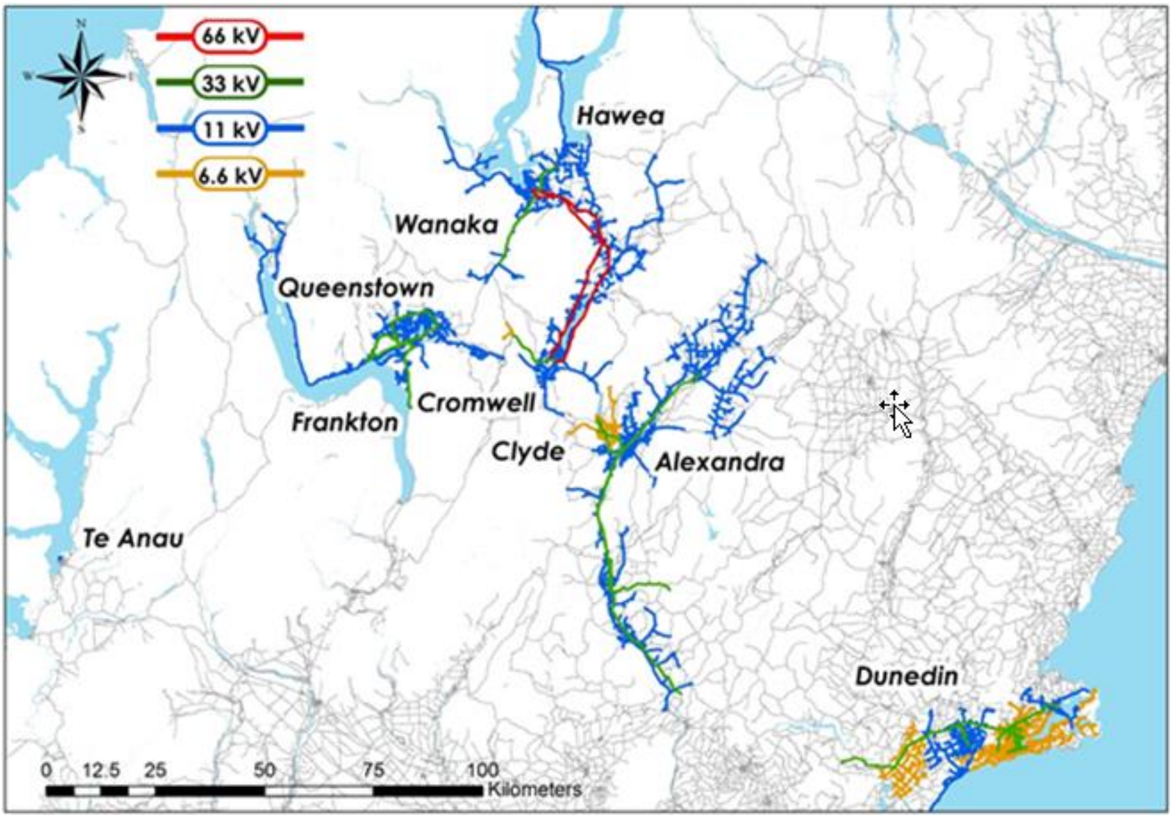
1. As a supplier of an essential service, we intend to set fair and reasonable prices for the specific individual demands of small, large and seasonal electricity users that have shared access to our network. This document outlines the pricing methodology Aurora Energy uses to determine its delivery prices.

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

1.2. Aurora Energy's Distribution Network

3. Aurora Energy is served from five GXPs; three in Central Otago and two in Dunedin. Due to their relatively homogenous characteristics, the South Dunedin and Halfway Bush GXPs in Dunedin form a single pricing area, as do the Clyde and Cromwell GXPs in Central Otago. The Frankton GXP forms a standalone pricing area servicing Queenstown. We also operate a small embedded network (residential subdivision) at Te Anau, which takes supply from The Power Company network. Figure 1, below, shows the geographic arrangement of the network.

Figure 1: Aurora Energy distribution network



1.3. Price Setting Context

4. The Commerce Commission (the Commission) regulates the maximum annual revenue Aurora Energy can earn from its customers and the minimum quality of service it must deliver. In June 2020, we applied to the Commission for a Customised Price-Quality Path (CPP) to ensure we can keep delivering a safe network, stabilise reliability, and address the emerging risks of an ageing network.

5. On 31 March 2021, the Commission published its final decision on our CPP application, along with the *Aurora Energy Limited Electricity Distribution Customised Price-Quality Path Determination 2021*[1] (CPP Determination).

6. Given that the requirement to set prices for the CPP Assessment Period ending 31 March 2022 (RY22) preceded the publication of the CPP Determination, we relied on the *[Draft] Aurora Energy Limited Electricity Distribution Customised Price-Quality Path Determination 2021*[2] (Draft Determination) to calculate our target revenue for RY22, from which we then set prices.

7. The CPP Determination specifies that forecast revenue from prices in RY22 must not exceed $107,112,000, and is unchanged the Draft Determination. Accordingly, we have not made any changes to the prices that were set based on the Draft Determination.

8. However, the CPP Determination did vary our operational and capital expenditure allowances. These figures underpin the calculation of our target revenue, which is set out in section 3.4. On 31 March 2021, we disclosed our pricing methodology, with section 3.4 reflecting the Draft Determination. With the release of the CPP Determination, we have revised section 3.4 and are now publishing this revised version of the pricing methodology.

9. Preparing our CPP application has been a major focus for Aurora Energy over the past two years, as it is critical to ensuring Aurora Energy has the means to continue to improve the safety and reliability of the network. Now that the CPP application process is complete, we have renewed our focus on developing more cost-reflective and service-based pricing. Section 2 of this document details our first Board-approved pricing strategy and the workstreams that we will undertake over the next five years.

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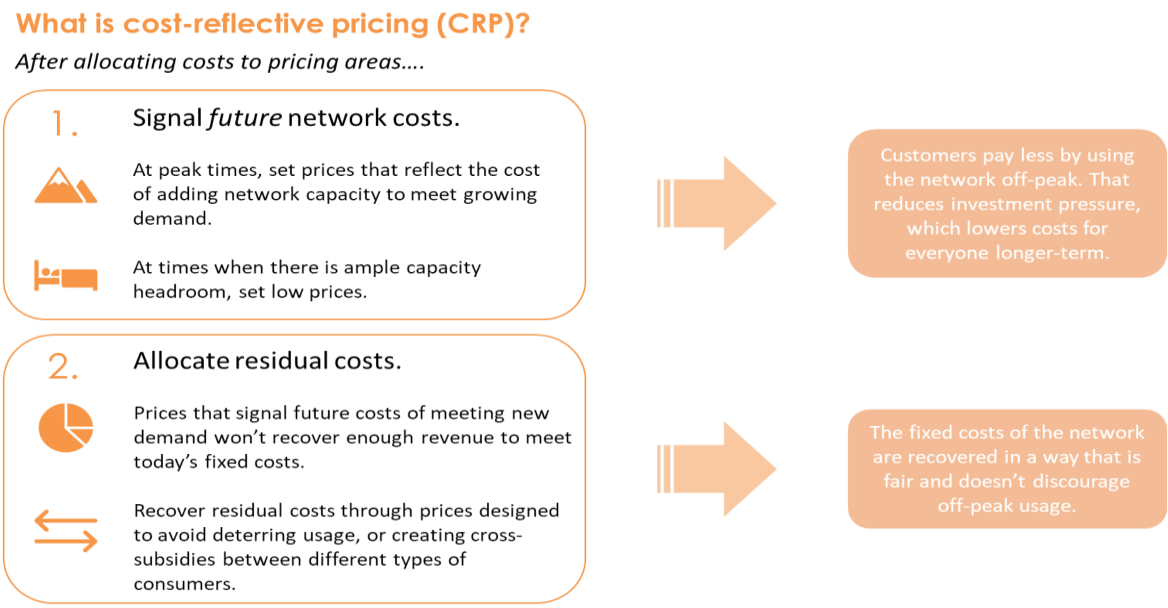
1 Available from https://comcom.govt.nz/regulated-industries/electricity-lines/projects/our-assessment-of-aurora-energys-investment-plan

2 Ibid

2. Pricing Strategy

10. Technology changes, such as more affordable rooftop solar and electric vehicles (EV), are making well-designed network pricing increasingly important. This is driving reform across New Zealand (and in countries such as Australia and the UK) toward cost-reflective pricing (CRP). Figure 2, below, describes CRP in more detail.

Figure 2: Cost reflective pricing



11. Aurora Energy is committed to implementing good practice pricing arrangements that play a constructive role in encouraging efficient network use and investment, for the long-term benefit of our customers.

12. Transitioning to CRP is a major shift that will take time to implement. With our CPP application process complete, it is timely for us to begin restructuring and rebalancing our pricing. We have developed a six-part strategy to guide this transition:

12.1. **Refine allocation to pricing areas** – this is an early priority that addresses an area of heightened community interest. Allocating costs to pricing areas will remain the first step in our annual pricing process, so we can make refinements independently of implementing CRP.

12.2. **Develop economic cost estimates** – to implement CRP we need sound estimates of the long-run marginal cost of supply (LRMC) in each of our pricing areas. This will be a new input to pricing based on engineering studies. We can begin reform with placeholder estimates, but will need to refine these as we progress towards full implementation.

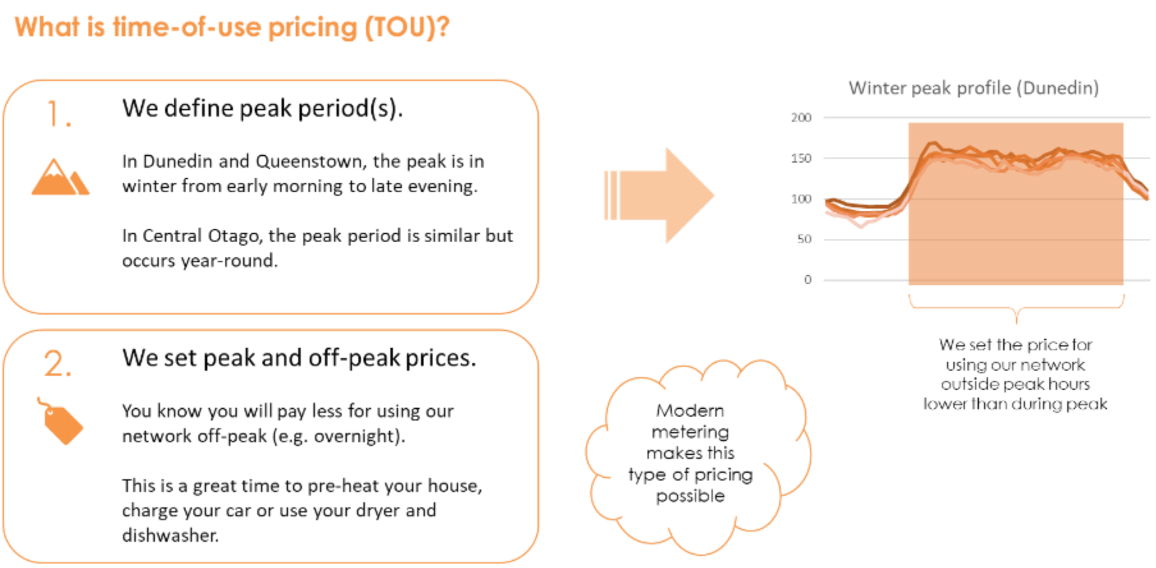
12.3. **Reform pricing structures** – for smaller customers, we think time-of-use (TOU) pricing (see Figure 3) is the best structure. Each pricing area should have peak periods that target times of investment pressure. We can put a mild form of TOU in place early (ahead of rebalancing the fixed, off-peak, and peak components). For larger customers, we want to consult on whether a more dynamic structure may be appropriate.

12.4. **Enhance controllability discounts** – we provide discounted prices now for managed hot water and space heating. We will need to align the design of these discounts with our new approach and would like to explore how we can make them available for managed EVs (and possibly other technologies) in the future.

12.5. **Simplify cost allocation within pricing areas** – much of the complexity in our current pricing arrangements comes from the way we allocate costs to load groups. As we move to full implementation, we want to explore a simpler approach complemented by more complete analysis of the subsidy-free range.

12.6. **Implement gradually and carefully** – we want to avoid unnecessarily exacerbating the bill pressure our customers already face as we implement our CPP work. Implementing pricing reform gradually and carefully will help us achieve this goal while still being able to realise the longer-term benefits of CRP.

Figure 3: Time-of-use pricing



13. Sections 3.1 to 3.7 provide more information on the context for pricing reform, and on each element of our strategy. For more information on our pricing strategy, please visit the pricing pages of our website (www.aurorenergy.co.nz).

2.1. Context

14. New technologies and trends (most notably solar generation, batteries, EVs, irrigation, and electrification) are increasing the scope for network pricing to influence investment and cost-shifting outcomes – for the better (if well designed) or for the worse.

15. Like most distributors in New Zealand, our existing pricing arrangements are not as good as they could be at signalling *future* costs. For example:

- for residential users in Dunedin and Queenstown, around one-third of revenue is recovered through energy-based ($ per kWh) charges on overnight, controlled or summer usage. This discourages usage that could be accommodated without driving network costs;[3]
- EV owners pay up to 20 cents per kWh for charging at home, even though off peak or interruptible charging could be accommodated at almost no cost;[4]
- price signals currently vary in strength across charge components that would work better if they provided consistent signals; and
- to the extent our pricing does signal the cost of peak usage (e.g., through winter rates and our load control discounts) this is not well aligned with the circumstances in each pricing area.

16. Pricing changes take years to develop and implement, with multi-year transitions often needed to limit bill shock. Signals then take time to flow to customer investment decisions and behaviours. As such, the focus for pricing reform should be on investment pressures 7+ years from today. Over that timeframe, price signal misalignment could drive outcomes such as:

- inefficient EV charging. EV uptake will grow rapidly and could cause significant network investment pressure if charging adds to peak demand. At the same time, usage charges for off-peak or interruptible demand deter usage that would not drive any new network costs;
- poorly targeted solar installations. Dunedin and Queenstown have peak demand in winter. Ideally, we should send a well calibrated and targeted price signal that encourages a helpful (but not excessive) investment in solar. This helps manage overall energy costs in our region, while avoiding large cost transfers from solar 'haves' to 'have nots';
- electricity rationing. Usage-based charges at times when there is ample network capacity deters consumption, contributing to under-heated or under-cooled homes, and suppressed electrification; and
- unnecessary network investment. Over time, well targeted pricing should produce flatter network profiles, supporting deferral of reinforcement work and potentially avoiding altogether a wave of low voltage (LV) reinforcement that may otherwise be needed to accommodate EVs or high solar uptake.

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3 Pricing is similar in Central Otago, but for part of that network there is a link between summer usage and investment pressure.

4 Prices vary by network area, metering configuration and season. 20 cents is the GST-inclusive price in Central Otago for the 2022 pricing year for a customer unable to access the night rate.

17. There is also a policy and regulatory focus on network pricing that reinforces the case for CRP and adds some elements:

   - Low Fixed Charge (LFC) – the Government may phase out low-user LFC regulations. This would improve scope to align price signals with underlying costs; and
   - cost allocation – there is some Government and regulatory focus on reviewing how costs are allocated between customer groups (e.g., households versus businesses).

18. Operationally, there is also scope for us to simplify our pricing. Our existing methodology focusses on allocation of current (not future) costs between customers. This drives complexity into our processes and pricing structures.

19. Finally, our recent CPP proposal and current economic conditions add to the context for pricing reform:

   - revenue path – we will have a relatively steep revenue path in coming years as we scale up capability and address a backlog of investment in our network assets. This heightens the need to carefully manage any additional bill shock that could flow from pricing reform;
   - pricing areas – our proposal stimulated interest in how we allocate costs to pricing areas. This makes reviewing regional cost allocation a logical first step for reform;
   - renewal focus – our plans focus on renewal in coming years, with a more tactical approach (where possible) to managing growth. This creates a window of opportunity to reform pricing before our investment focus returns to addressing growth pressures; and
   - economic uncertainty – the 2020 border closure has had a sharp impact on our communities. The future state of tourism and education is uncertain, which is adding network demand uncertainty.

20. These factors shape the impetus for reform, and the direction of our reform strategy as set out below.

2.2. Refine Allocations to Pricing Areas

21. Allocating target revenue to pricing areas is the first step of our pricing process each year. Our target revenue is cost-based (i.e., designed to recover our costs) and traditionally, we have allocated asset and operating costs based on network replacement cost estimates.

22. The CPP stimulated interest in this process, from our communities and regulators. Following a review commissioned by the Electricity Authority, we intend to refine our allocation methodology. We will implement incremental changes each year, starting from this year:

   - in RY22 we have made initial refinements to how we allocate operating costs;
   - in RY22 we will consult on a proposal to allocate asset-related costs using values recorded in our regulatory asset base (RAB); and
   - in future years, we will explore options to further refine the proxies we use to allocate types of operating costs.

23. Consulting on the RAB-based allocation also allows us time to complete assurance work on the models we use to allocate our RAB to pricing areas. Ultimately, we think this approach will provide a robust basis for allocation.

2.3. Develop Economic Cost Estimates

24. To implement CRP, we need to develop sound estimates of how an increase in usage translates into more (or earlier) investment in the capacity of the network (and any other capital or operating costs that flow from the new capacity). This is termed the LRMC and will vary by pricing area.

25. To estimate LRMC values, we will need to develop a suitable methodology and complete engineering studies. This is likely to involve developing one or more LRMC values for our LV networks, and LRMC estimates for the high-voltage networks and grid connection in each pricing area. In future, we may also require an LRMC value for network reinforcement needed to support high solar penetration.

26. We can use placeholder LRMC values initially but will need better estimates as we 'tune' pricing levels for restructured prices.

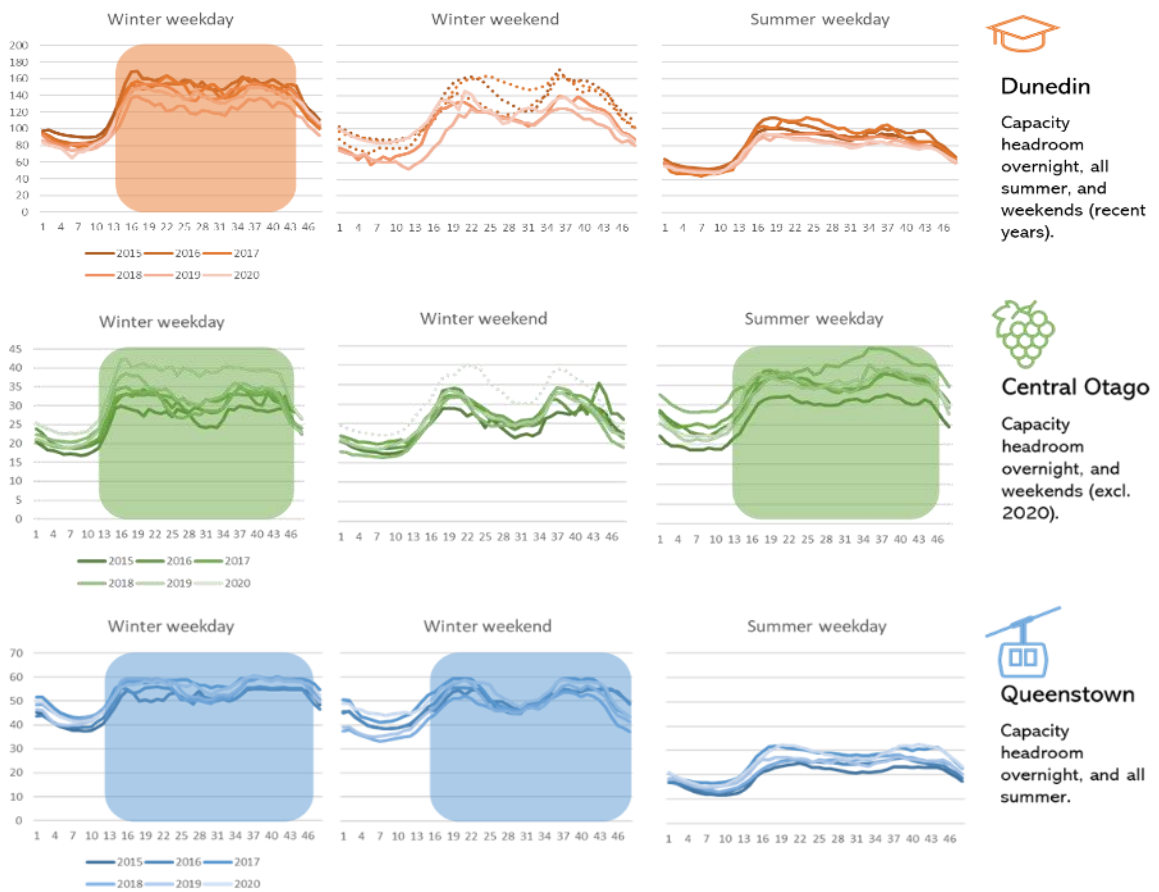
2.4. Reform Pricing Structures

27. We think TOU pricing is the best structure for small customers for now. TOU pricing can send efficient signals for the appliance purchase and usage decisions that smaller customers typically make, can now be implemented by most retailers, and is relatively easy for customers to understand.

28. To design appropriate TOU pricing, we need to set peak periods that correspond to times of network investment pressure. These are different in each of our pricing areas – for example, weekends may be off-peak in Dunedin but not Queenstown, and summer may be off-peak in Queenstown, but not Central Otago. Confirming suitable peak periods will be an early priority. Figure 4 shows the demand profiles of our three main pricing areas.

29. For larger commercial customers who may be better placed to manage their daily operations, we want to test whether a more dynamic form of pricing – such as coincident peak demand – may be the best option.

Figure 4: Demand profiles



30. By RY24, we think we will be ready to introduce new structures, including a mild form of TOU (with peak versus off-peak pricing levels close to current pricing) and potentially a first set of changes for larger customers.

31. Implementing structures ahead of rebalancing the peak, off-peak and fixed components should allow for a smoother transition.

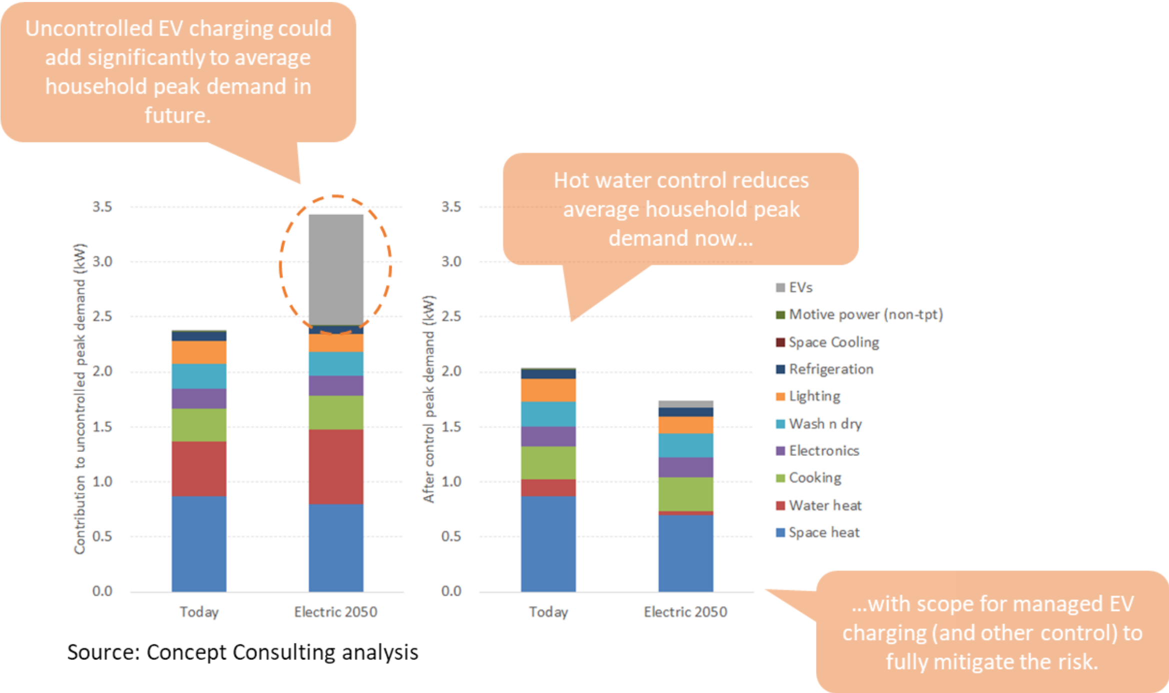
2.5. Enhance Controllability Discounts

32. We think TOU pricing should be complemented by discounting arrangements for managed loads. This helps ensure that very 'shiftable' loads do not cause a surge of demand at the onset of the off-peak periods.

33. We effectively apply managed load discounts already to ripple-controlled water heating. As we transition to new structures and rebalance pricing levels, we need to ensure the discount for controllability is consistent with our LRMC signalling and we want to explore how we can apply discounts for managed EV charging (and potentially other technologies).

34. Encouraging managed EV charging and preserving managed water heating are key strategies for mitigating the risk of needing large scale LV network upgrades. Figure 5 shows the current controlled and uncontrolled peak demand.

Figure 5: Controlled and uncontrolled peak demand

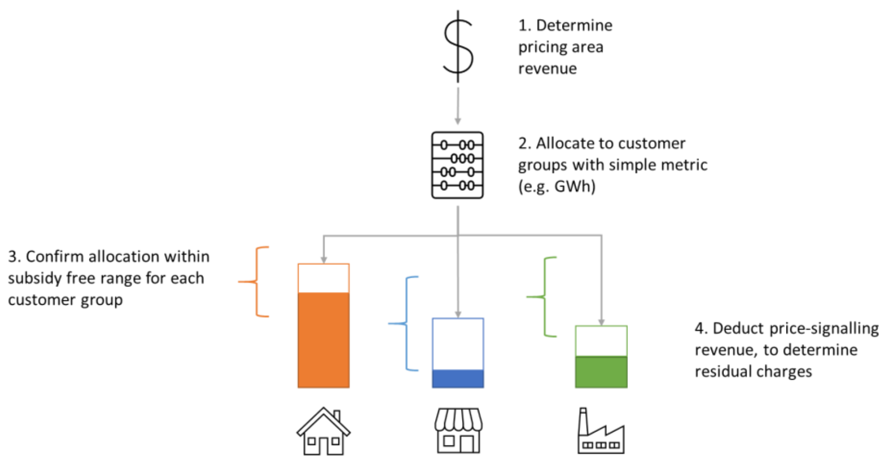


Source: Concept Consulting analysis

2.6. Simplify Cost Allocation Within Pricing Areas

35. Much of the complexity in our current pricing is a legacy of methods used to allocate an accounting view of costs to different load groups. With CRP, the emphasis shifts to signalling economic costs and simpler approaches to allocating residual costs become possible. Figure 6 shows our cost allocation within pricing areas.

Figure 6: Cost allocation within pricing areas



36. To support simpler allocation, we will need a more complete picture of the subsidy-free range for each customer group. Implementing simpler allocations may also help us to remove price components (e.g., some large users currently have fixed, capacity, distance, reactive power, and demand prices) and potentially simplify our load groups (e.g., with fewer bands).

2.7. Implement Gradually and Carefully

37. With our CPP programme of catch-up investment and capability build underway, charges will already have relatively large year-on-year changes in pricing levels. While implementing pricing change is important, we want to make sure we set a pace that:

- avoids unduly exacerbating bill pressure for those customers for whom new prices will cause higher bills (e.g., because they are low or peaky users);
- allows for careful planning and design, including the analysis that will be needed for key inputs such as LRMC and subsidy-free values; and
- supports effective consultation and engagement, which is crucial for informing us and our customers.

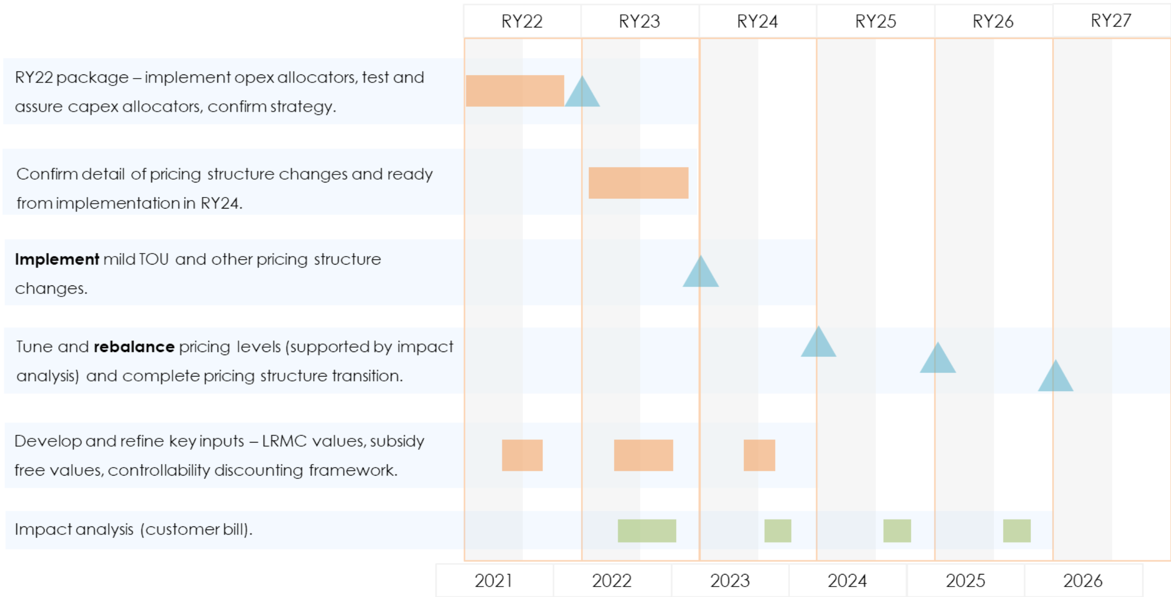
38. We will start straight away, with activities for the coming year (RY22) including:

- consultation on this strategy;
- implementation of new operational expenditure allocation metrics;
- consultation, testing and assurance work on RAB-based capital cost allocation metrics; and
- confirming methodologies for LRMC and subsidy-free studies.

39. This work will provide a foundation for confirming new pricing structures during RY23, for implementation in April 2023. From there, our initial plan is to transition to target pricing levels in three steps, with the strategy fully implemented from April 2026.

40. We think this timeframe is realistic and fits well with an aim that pricing should help moderate post-CPP investment pressures from around 2027. Figure 7 summarises our timeline for implementing pricing changes.

Figure 7: Summary distribution pricing roadmap



2.8. Customer Impact

41. As we implement our strategy, it will alter our customers' bills – some will pay less, and some will pay more. Longer-term, the goal is that everyone pays less because prices are effective at softening investment pressures – reducing the costs we need to recover (compared to what they could have been).

42. Our strategy calls for gradual and incremental change, with more detailed design and impact analysis at each step of the process. As such, we cannot provide a full assessment of how customer bills will be impacted at this early stage.

3. RY22 Pricing

3.1. Customer Consultation

43. We regularly seek the views of customers to understand their expectations of service quality and price. The lead up to our CPP proposal in June 2020 provided the opportunity to conduct more thorough customer engagement, including the establishment of customer panels, interactive online engagement and research, community panels, drop-in sessions, and one-on-one meetings.

44. Our customers told us that they support Aurora Energy's investment in essential infrastructure, but the impact of price increases was a major concern. Most customers were happy with the current level of reliability and did not support reliability improvements if they resulted in higher prices. This feedback is consistent with previous years' surveys.

45. Some stakeholders also had concerns about whether the allocation of costs between the different pricing areas was equitable. We have begun to address these concerns in RY22 by making refinements to the allocation of operating costs to pricing areas, and we intend to consult with customers about further refinements to cost allocations in September and October 2021.

3.2. Changes to the Pricing Methodology for RY22

46. In response to stakeholder feedback, we have made improvements to the way we allocate operational costs to pricing areas. Historically, we have allocated operational costs to pricing areas based on the estimated replacement cost (RC) of assets in each pricing area. This year we have allocated operational costs to each pricing area based on a set of proxy allocators that reflect the underlying cost to supply electricity to each pricing area.

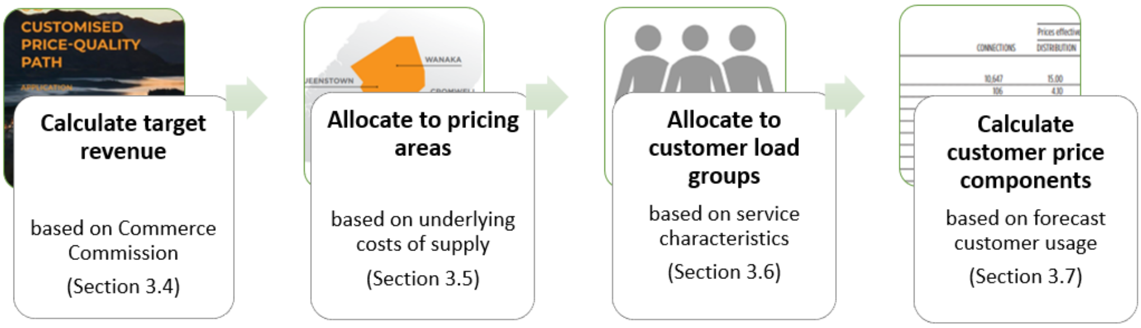
47. These improvements also provide stakeholders with greater transparency about the allocation of operational costs to pricing areas and address concerns raised during customer consultation. The details of our cost allocations to pricing areas are provided in section 3.5.

3.3. Pricing Approach

48. Aurora Energy's pricing methodology is designed to support an efficient level of investment in our network for the long-term benefit of customers, and to comply with the Electricity Authority's 2019 pricing principles (Appendix A). Prices are set to signal the underlying costs of supplying services, allowing customers to make efficient decisions about how they connect to, and use, our network. This allows Aurora Energy to plan and operate our network assets efficiently, safely, and reliably.

49. Figure 8 summarises the four steps Aurora Energy followed to set customer prices for RY22, with more detail provided in sections 3.4 to 3.7.

Figure 8: Pricing process



3.4. Calculate Target Revenue

50. The Commission regulates the maximum annual revenue Aurora Energy can earn from its customers and the minimum quality of service it must deliver. In June 2020, we applied to the Commission for a CPP to ensure we can keep delivering a safe network, stabilise reliability, and address the emerging risks of an ageing network.

51. On 31 March 2021, the Commission published its final decision on our CPP application, along with the CPP Determination.

52. Given that the requirement to set prices for RY22 preceded publication of the CPP Determination, we relied on the Draft Determination to calculate our forecast allowable revenue and our target revenue for RY22, from which we then set prices.

53. While the CPP Determination specifies that forecast revenue from prices in RY22 must not exceed $107,112,000, which is unchanged from the Draft Determination, it did vary our operational and capital expenditure allowances, which results in a $10.8m deferral of revenue to future periods. This has meant that the components of our target revenue, set out in Table 1 have changed based on the CPP Determination.

54. For transparency, the components of target revenue and the revenue deferral based on both the Draft Determination and the CPP Determination are set out in Table 1, along with a comparison to the previous year's values.

55. The CPP Determination confirms that our RY22 revenue will increase by $9.7m (10%) when compared to the previous year, and result in an average price increase of 8.4% across all price categories.

Table 1: Components of target revenue ($m)

Component	RY22 -Draft Determination	RY22 – Final Determination	RY21
Capital related costs:			
Return on capital	38.7	35.4	16.8
Depreciation	20.7	20.7	19.8
Tax	4.8	5.3	9.4
Asset revaluations and other regulatory revenue	(11.2)	(11.1)	(6.1)
Operational costs:			
System operations and network support	23.6	32.5	30.2
Routine and corrective maintenance and inspection	10.4	10.5	7.6
Vegetation maintenance	4.2	5.6	5.6
Service Interruptions and emergencies	4.8	4.8	4.0
Passthrough and recoverable costs:			
Transmission costs and ACOT	27.3	27.3	28.3
CPP recoverable costs	2.5	2.5	-
Local authority rates	1.0	1.0	0.8
Commerce Act levies	0.4	0.4	0.2
Electricity Authority levies	0.3	0.3	0.3
Utilities Disputes levies	0.1	0.1	0.1
Fire & Emergency New Zealand (FENZ) levies	0.0	0.0	0.0
Quality Incentive	(0.6)	(0.6)	(0.6)
IRIS – Capex	(1.4)	(1.5)	-
IRIS – Opex	(14.4)	(15.4)	(18.5)
Passthrough balance account[5]	-	-	(0.5)
Target Revenue (before revenue limit applied)	**111.2**	**117.9**	**97.4**
Less: Revenue deferred to future periods	(4.1)	(10.8)	-
Target Revenue	**107.1**	**107.1**	**97.4**

[5] In accordance with the Commission's draft CPP determination, the Passthrough balance account is no longer part of the forecast allowable revenue calculation

56. While Table 1 has been updated to reflect the parameters of the Commission's final decision on our CPP application, the remainder of this document reflects pricing decisions that were based on the Draft Determination.

3.5. Allocate to Pricing Areas

57. The second step in Aurora Energy's pricing process is to allocate the target revenue to our four pricing areas:

- Dunedin
- Central Otago and Wanaka
- Queenstown
- Heritage Estate, Te Anau.

58. We have chosen proxy allocators for each component of target revenue, to align the revenue we collect from each pricing area with the underlying costs of supplying services. Table 2 details the allocation basis and rationale for allocating each component of target revenue to a pricing area.

Table 2: Pricing area allocators

Component	Allocator	Rationale
Capital related costs:		
– Return on capital – Depreciation – Tax – Asset revaluations and other regulatory revenue	Asset replacement cost	All capital related costs are allocated to pricing areas in proportion to that pricing area's share of the total network assets. This approach reflects the level of network investment required by Aurora Energy to provide services. Asset replacement cost is currently used for determining the relative proportion of network assets. We have committed to consulting with customers, later this year, about potential improvements to this approach.
Operational costs:		
System operations and network support	ICP count	This expenditure is an overhead expense and is considered best socialised across the network to recognise scale benefits. We have used ICP count to do this.
Routine and corrective maintenance and inspection	Total circuit length	Maintenance and inspections tend to scale proportionately to the size of the network. Total circuit length explains the relative scale of each pricing area's network.
Vegetation management	Overhead circuit length	Vegetation management costs are predominantly driven by vegetation conflicts with overhead lines. The overhead circuit length explains each pricing

Component	Allocator	Rationale
		area's contribution to total vegetation management expenditure.
Service interruptions and emergencies	– 50% allocated by ICP count – 50% allocated by total circuit length	Faults may occur at individual ICPs or at distribution equipment affecting wide areas. ICP count explains individual fault contributions in each pricing area while total circuit length explains the scale of the network in each pricing area, over which faults may occur.
Passthrough and recoverable costs:		
Transmission costs and ACOT	Directly allocated by Transpower	These expenses are directly allocated to GXPs based on Transpower's Transmission Pricing Methodology, except for the shared 220/110kV Cromwell transformer supplying both Cromwell and Frankton and provided under a New Investment Contract. The allocation between Frankton and Cromwell is determined based on each GXP's contribution to regional coincident peak demand (RCPD), as determined by Transpower.
CPP recoverable costs	ICP count	The CPP is fundamentally a business plan and therefore an overhead expense. It is considered best socialised across the network to recognise scale benefits. We have used ICP count to do this.
Local authority rates	Asset replacement cost	Rates are levied by councils based on RAB value. Some rates are directly attributable to pricing areas; however, where allocation is required, we have maintained our allocation to pricing areas based on estimated asset replacement cost. Subject to consultation later in 2021, we intend to use RAB value to allocate rates from 1 April 2022.
Commerce Act levies	Asset replacement cost	Commerce Act levies are allocated to distributors based on RAB value. We have maintained our allocation to pricing areas based on estimated replacement cost. Subject to consultation later in 2021, we intent to use RAB value to allocate rates from 1 April 2022.
Electricity Authority levies	– 80% allocated by kWh – 20% allocated by ICP count	This method of allocation approximates the way the Electricity Authority levies are allocated to distributors.

Component	Allocator	Rationale
Utilities Disputes levies	ICP count	The Utilities Disputes levies are an overhead expense and are considered best socialised across the network to recognise scale benefits. We have used ICP count to do this.
FENZ levies	Asset replacement cost	FENZ levies are broadly based on asset values, via insurance premia. We have allocated FENZ levies to pricing areas based on the estimated asset replacement value of each pricing area. Subject to consultation later in 2021, we intend to use RAB value to allocate rates from 1 April 2022.
Quality incentive adjustment	ICP count	The quality incentive in RY22 is a penalty for not meeting regulated quality targets. At this time, the incentive (refund) is socialised across the network to recognise scale benefits. We have used ICP count to do this.
IRIS – Capex	Estimated replacement cost	The capex IRIS incentive in RY22 is a penalty for overspending capital expenditure allowances in the previous regulatory period. We have allocated the capex IRIS incentive (refund) amount based on the estimated asset replacement cost of each pricing area. Subject to consultation later in RY22, we intend to use RAB value to allocate the capex IRIS from 1 April 2022.
IRIS – Opex	Previous year's distribution charges	The opex IRIS incentive in RY22 is currently a penalty for overspending operational expenditure allowances in the previous regulatory period. We have allocated the opex IRIS incentive (refund) based on the previous year's distribution line charges in each pricing area.
Revenue deferred to future periods	Pro-rated	The revenue deferred to future periods has been pro-rated across all other components listed in Table 1. This approach recognises that the revenue deferred cannot be allocated to a specific cost item.

59. Each component of target revenue is allocated to pricing areas based on the allocator in Table 2 and the allocation percentages specified in Table 3.

Table 3: Pricing area allocation percentages

Cost Allocation	Pricing Area			
	Dunedin	Central	Queenstown	Te Anau
Asset replacement cost	46.0%	35.3%	18.5%	0.2%
ICP count	60.9%	23.5%	15.4%	0.2%
Total circuit length	38.9%	44.8%	16.1%	0.2%
Overhead circuit length	43.9%	45.6%	10.5%	0.0%
Transmission costs and ACOT	63.3%	14.7%	22.0%	0.0%
kWh	59.5%	20.8%	19.6%	0.1%
Prior year's distribution charges	48.7%	33.5%	17.7%	0.1%

60. The resulting target revenue to be recovered from each pricing area is detailed in Table 4.

Table 4: Total target revenue by pricing area

Components ($m)	Dunedin	Central	Queenstown	Te Anau	Total
Capital related cost	23.5	18.0	9.4	0.1	51.0
Operating Expenditure	21.8	13.3	6.3	0.0	41.4
Passthrough and recoverable costs	11.3	(0.3)	3.7	(0.0)	14.7
Total target revenue	56.6	31.0	19.4	0.1	107.1
% of target revenue	52.8%	29.0%	18.1%	0.1%	100%

3.6. Allocate to Customer Load Groups

61. After determining the target revenue for each pricing area, we then further allocate target revenue to customer load groups. Our categorisation of load groups is based on physically distinguishable characteristics and recognises that customers use our network differently. Large customers make proportionately greater use of high voltage (HV) network elements than smaller customers. We take this into account in our pricing methodology by establishing load groups and allocating target revenue to these load groups proportional to their use of the network. Our approach means that prices will differ between pricing areas, and between load groups. The load groups are shown in Table 5.

Table 5: Customer load groups

Load Groups	Description
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 a distribution transformer – the transformer may be owned by the customer and connections share general HV asset costs.
Load Group 5	Three phase connections – generally HV customers and have dedicated HV lines / cables to supply the connection.

62. Target revenue for each pricing area is allocated to customer load groups by choosing proxy allocators for each revenue component. Table 6 details the allocation basis and rationale for allocating each component of target revenue to a customer load group.

Table 6: Customer load group allocators

Component	Allocator	Rationale
Capital related costs:		
– Return on capital – Depreciation – Tax – Asset revaluations and other regulatory revenue	Asset replacement cost	All capital related costs are allocated to load groups based on each load group's use of the LV and HV network. Asset replacement cost is currently used to determine the relative proportion of network assets. We have committed to consulting with customers in RY22 about potential improvements to this approach.
Operational costs:		
System operations and network support	ICP count	This expenditure is an overhead expense and is considered best socialised across load groups to recognise scale benefits. We have used ICP count to do this.
Routine and corrective maintenance and inspection	Co-incident Maximum Demand (CMD)	Within each pricing area, maintenance costs are allocated to each load group based on its contribution to CMD.

Component	Allocator	Rationale
Vegetation management	CMD	Within each pricing area, vegetation costs are allocated to each load group based on its contribution to CMD.
Service interruptions and emergencies	– 50% allocated by ICP count – 50% allocated by CMD	Faults may occur at individual ICPs or at distribution equipment affecting wide areas. ICP count explains individual fault contributions in each load group while CMD reflects each load group's contribution to the maximum system demand.
Passthrough and recoverable costs:		
Transmission and ACOT	AMD and CMD	Transmission and ACOT costs have been allocated to customer load groups using AMD and CMD, which approximates the method of cost allocation used by Transpower.
CPP recoverable costs	ICP count	The CPP is fundamentally a business plan and therefore an overhead expense. It is considered best socialised across load groups to recognise scale benefits. We have used ICP count to do this.
Local authority rates	Asset replacement cost	Rates are levied by councils based on regulatory asset value, so we have maintained our allocation to load groups areas based on each load group's use of the LV and HV network.
Commerce Act levies	Asset replacement cost	Commerce Act levies are allocated to distributors based on RAB value, so we have maintained our allocation to load groups based on estimated replacement cost.
Electricity Authority levies	– 80% allocated by kWh – 20% allocated by ICP count	This method of allocation approximates the way the Electricity Authority levies are allocated to distributors.
Utilities Disputes levies	ICP count	Utilities Disputes levies are an overhead expense and are considered best socialised across load groups to recognise scale benefits. We have used ICP count to do this.
FENZ levies	Asset replacement cost	FENZ levies are broadly based on asset values, via insurance premia, so we have maintained our allocation to load groups based on estimated replacement cost.
Quality incentive adjustment	ICP count	The RY22 quality incentive is a penalty for not meeting regulated quality targets. The incentive (refund) is socialised across load groups to

Component	Allocator	Rationale
		recognise scale benefits. We have used ICP count to do this.
IRIS – Capex	Asset replacement cost	The RY22 capex IRIS incentive is a penalty for overspending capital expenditure allowances in the previous regulatory period. We have allocated the capex IRIS incentive (refund) amount based on the estimated replacement value of each load group's use of network assets.
IRIS – Opex	Previous year's distribution charges	The RY22 opex IRIS incentive is currently a penalty for overspending operational expenditure allowances in the previous regulatory period. We have allocated the opex IRIS incentive (refund) based on the previous year's distribution line charges for each load group.
Revenue deferred to future periods	Pro-rated	The revenue deferred to future periods has been pro-rated across all other components listed in Table 1. This approach recognises that the revenue deferred cannot be allocated to a specific cost item.

63. The allocation percentages used to allocate target revenue to customer load groups are shown in Table 7.

Table 7: Load group allocation percentages

	Load Group					
Cost Allocators	SL	L1	L2	L3	L4	L5
ICPs	0.0%	92.1%	7.3%	0.4%	0.2%	0.0%
kWh	0.7%	49.9%	20.8%	10.5%	13.2%	4.9%
Prior year distribution rev	0.4%	65.7%	18.1%	8.2%	6.6%	1.0%
AMD	0.6%	58.8%	16.4%	8.7%	11.6%	3.9%
CMD	0.0%	73.%	21.0%	5.6%	0.0%	0.0%
Asset replacement cost	0.5%	68.9%	20.7%	5.7%	3.4%	0.8%

64. The allocators chosen in Table 6 are proxy allocators that explain the underlying costs of serving each customer load group. The actual costs of supplying a customer load group cannot be precisely determined and must instead be estimated, since network assets and costs are usually shared between multiple load groups.

65. When applying the load group allocations described in Table 6 in a purely formulaic manner, we observed unexplained variations in the load group revenue allocations compared to the previous

year. This is not reflective of actual changes in network cost characteristics, which have remained relatively constant between RY21 and RY22.

66. Accordingly, we have applied judgement to moderate revenue changes between load groups within the same pricing area. Table 8 shows the revenue allocation by load group, before and after the application of judgement.

Table 8: Target revenue by customer load group ($m)

Customer Load Group	RY22 target revenue before judgement applied	Judgement applied	RY22 target revenue after judgement applied
Dunedin			
Street Lighting	2.0	(1.5)	0.5
Load Group 0	0.0	0.1	0.1
Load Group 1	42.9	(5.9)	37.0
Load Group 2	7.9	1.0	8.9
Load Group 3 & 3A	2.3	2.0	4.3
Load Group 4	1.0	3.4	4.4
Load Group 5	0.4	0.9	1.3
Total Dunedin	56.5		56.5
Central			
Street Lighting	0.7	(0.6)	0.1
Load Group 0	0.0	0.2	0.2
Load Group 1	20.0	(0.6)	19.4
Load Group 2	6.8	(1.2)	5.6
Load Group 3 & 3A	2.1	0.6	2.7
Load Group 4	0.8	1.6	2.4
Load Group 5	0.1	0.0	0.1
Total Central	30.5		30.5

Customer Load Group	RY22 target revenue before judgement applied	Judgement applied	RY22 target revenue after judgement applied
Queenstown			
Street Lighting	0.2	(0.1)	0.1
Load Group 0	0.0	0.1	0.1
Load Group 1	12.4	(1.3)	11.1
Load Group 2	5.0	(0.6)	4.4
Load Group 3 & 3A	1.1	0.4	1.5
Load Group 4	0.6	1.3	1.9
Load Group 5	0.1	0.1	0.2
Total Queenstown	19.4		19.4
Te Anau			
Street Lighting	0.0	0.0	0.0
Load Group 1	0.1	0.0	0.1
Load Group 2	0.0	0.0	0.0
Total Te Anau	0.1		0.1
Distributed generation	0.6		0.6
TOTAL NETWORK	**107.1**		**107.1**

3.7. Calculate Customer Price Components

67. Within load groups in each pricing area, we adopt a pricing structure that is intended to reflect the impact of customers' consumption (and other) decisions on the key drivers of our 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 between load groups. For instance, if costs were simply allocated on a customer number basis, then a disproportionate amount of cost would be recovered from residential customers. Conversely, if costs were allocated based on electricity conveyed, then a disproportionate recovery from larger customers would occur.

68. As would be expected, the load groups comprising smaller customers are allocated costs attributable to HV and LV elements of the network, whilst load groups comprising larger customers are generally allocated costs attributable to HV network elements only.

69. For larger customers (i.e., in load groups L3, L4 and L5), costs are recovered through:

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

70. Aurora Energy considers that capacity, distance, and peak demand are the key drivers of the costs created by these customer groups and therefore prices determined on this basis are broadly cost-reflective.

71. For smaller customers on General pricing (i.e., load groups L1 and L2), costs are recovered through:

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

72. Aurora Energy considers that capacity and peak demand are key drivers of costs created by these customer groups and therefore prices determined on this basis are broadly cost-reflective.

73. For smaller customers on Residential pricing (i.e., load groups L1 and L1A - refer to section 9.1), costs are recovered through:

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

74. The price structure for Residential connections is not our preferred recovery mechanism, but has been partially forced upon us by the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004. These regulations require Residential customers 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.

75. The main weakness with Residential pricing comprising high variable charges is one of equity, in that revenue is under-recovered from customers with low annual usage, and over-recovered from customers with high annual usage. This weakness exacerbated by the deployment of small-scale distributed generation (SSDG), since customers that can afford SSDG systems inevitably shift the burden of network cost recovery to customers that cannot afford such systems.

76. Table 9 describes the allocation of target revenue to price components. Further detail about each price components is provided in sections 3.7.1 to 3.7.3.

Table 9: Target revenue by price component ($m)

	Price Component	Dunedin	Central Otago and Wanaka	Queenstown	Te Anau	Total	% of Total
Distribution ($000's)	Fixed	3.2	1.5	1.0	0.0	5.6	5.2%
	Volumetric	24.9	17.0	7.7	0.1	49.8	46.6%
	Capacity kVA	8.3	6.0	3.6	0.0	17.9	16.7%
	KVA-KM	0.3	1.1	0.2	-	1.5	1.4%
	CPD kW	7.2	5.0	2.8	0.0	14.9	13.9%
	Equipment	0.5	0.2	0.2	-	0.9	0.8%
	Street lighting	0.4	0.1	0.1	0.0	0.6	0.6%
	Generation	0.1	0.5	0.0	-	0.6	0.6%
	Subtotal	**44.9**	**31.3**	**15.5**	**0.1**	**91.9**	**85.8%**
Pass-through ($000's)	Fixed	0.0	(0.0)	0.2	-	0.2	0.2%
	Volumetric	6.7	(0.6)	1.8	-	7.9	7.4%
	Capacity kVA	(1.9)	(1.5)	(0.6)	-	(4.1)	(3.8%)
	CPD kW	6.9	1.9	2.4	-	11.1	10.4%
	Street lighting	0.0	0.0	0.0	-	0.0	0.0%
	Subtotal	**11.7**	**(0.3)**	**3.8**	**-**	**15.2**	**14.2%**
Total		**56.6**	**31.0**	**19.4**	**0.1**	**107.1**	**100.0%**

3.7.1. Distribution Cost Recovery Components

Residential Distribution Price Components

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

Fixed Price

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

Volumetric Price

79. Volumetric prices are defined by the existing metering arrangements for each network area.

80. 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.

81. 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.

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

Closure of Dunedin All-Inclusive Price Options

83. Aurora Energy closed the all-inclusive price option to new customers in Dunedin from 1 April 2017.

84. 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.

85. 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 customers will have higher and lower proportions of controlled and uncontrolled load to that assumed.

86. 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. Customers 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 Energy or its approved contractors, and therefore is difficult to monitor.

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

3.7.2. General Distribution Price Components

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

Fixed Price

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

Capacity Price

– Connections metered at low voltage.

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

The basis for the annual Assessed Capacity is the minimum fuse size, mains size or standard distribution transformer size required to supply the maximum anytime power demand. Normally this will be the minimum fuse size for capacity up to 276 kVA and installed distribution capacity for capacity greater than or equal to 300 kVA. A further explanation of connection capacities is given in Aurora Energy'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., HV lines and cables. The use of these assets is more directly related to the capacity of the individual connections.

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

Distance Price

90. For the L3, L3A, L4 and L5 load groups (assessed capacity 150 kVA or greater), the costs associated with HV 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 Energy zone substation and then to the nearest Transpower supply point.

91. 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 price signals this fact.

Control Period Demand Price

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

93. CPD (kW) is the energy used at the installation when Aurora Energy 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 customer commences during the year a negotiated CPD will apply until a full winter is completed.

94. 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 customers 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.

95. Where it is not presently economic to install CPD metering for connections such as Load Group 1 and Load Group 2, then any charges that would normally be recovered via a CPD 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 Appendix C.

96. 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 customers to accept controlled loads.

97. By signalling the impact of network coincident demand in this way, Aurora Energy can defer the need for investment in more capacity, which is a very expensive alternative. Customers 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.

Equipment Price

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

Power Factor Price

99. Aurora Energy will charge a power factor price for connections where it is identified that the poor power factor for a connection is negatively impacting the voltage supplied by the distribution network. Poor power factor is defined as a power factor lower than 0.95 lagging.

100. The power factor quantity is that amount of equivalent corrective capacitance (kVAr) required to improve the power factor 0.95 lagging.

3.7.3. Pass-through Cost Recovery Prices

Residential Connections

101. 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.

General Connections

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

Loss and Constraint Excess Payments

103. Loss and Constraint Excess Payments are credits rebated by Transpower because 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 based on each retailer's total pass-through charges for the month in which the rebate applied. This credit is currently available in mid-June for the month of April.

104. It would be preferable to allocate Loss and Constraint Excess Payments based on 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 DG allowance comprising approximately 79% of the total pass-through recovery, Aurora Energy considers that the benefit of greater precision is not likely to be high.

105. Aurora Energy consulted with retailers in 2016 regarding ceasing the direct pass-through of Loss and Constraint Excess Payments. Aurora Energy 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 Energy received conflicting feedback to this proposal, and will consider this matter further in the future.

4. Customer Connection Definitions

4.1. Residential Connection Definition

106. 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 customers' 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.

107. 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).

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

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

109. 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.

110. In addition to the above criteria, we apply Residential pricing to ICPs in the following situations:

4.1.1. Potable Water Supplies for Residential Connections

111. Where customers 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.

112. 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).

4.1.2. Sheds and Out-buildings Supplied from Separate Connections

113. Where sheds, out-buildings and similar are supplied from a separate connection to that supplying a residence, as occurs commonly on larger lifestyle properties, the separate connection is categorised as a General connection and not a Residential connection. The only configuration that will permit a shed, out-building or similar to be supplied under Residential pricing is for the shed, out-building or similar to be sub-mained from the residence.

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

114. There are high capacity connections (greater than 15kVA) on the Aurora Energy network that are a customer'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 us to offer LFC compliant pricing to low-use primary residences, irrespective of the capacity of the connection.

115. To comply with this requirement, Aurora Energy 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 data for the customer is 9,000kWh or less. Transfer to Residential pricing will be assessed considered following a request received from a retailer or customer.

116. If the customer has not been the occupier of the residence for the most recent 12-month period, either the customer or the customer's retailer will need to provide us with details of the customer's previous residence (or residences if more than one) during that period, so we can assess the customer's total annual consumption. If the customer's previous residence is outside of Aurora Energy's network, the customer or the customer's retailer will need to obtain and provide us with the consumption information relating to that previous residence.

4.1.4. Temporary Connections Where the Customer is Living On-site

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

4.2. General Connection Definition

118. General connections are all connections that are not Residential connections as, defined in section 1; however, there are several sub-sets of General connections which each have their own qualification criteria.

4.2.1. Unmetered Load

119. There are situations where metering is not required for load at a single connection due to its limited consumption. The Code allows for connections to be unmetered if it is reasonably expected that the load, in any rolling 12-month period, will be no greater than:

- 3,000kWh; or
- 6,000kWh if the load is predictable and of a type approved and published by the EA.

120. According to the Code, the approved types of load which may be unmetered up to 6,000kWh are:

- amenity lighting (including billboards, advertising hoardings, bus shelters, phone booths, school signs and public conveniences);
- street lighting (excluding street lighting that is DUML);
- right of way lighting;
- under veranda lighting;
- floodlighting where the usage of the lights is regular on a daily basis;
- traffic lights;
- radio transmitters/receivers and communications cabinets;
- distribution equipment; and
- sewage and storm water pumps.

121. The categories above are permitted to be unmetered connections provided their daily use can be reasonably predicted. It must be known when they will be used and for how long.

122. For connection applications for new unmetered connections, we will also seek confirmation from the electricity retailer that they will accept the connection as unmetered, as the electricity retailer is the industry participant who is responsible for the compliance of the metering setup of each connection.

123. Aurora Energy charges a single Daily Fixed Price for unmetered connections.

4.2.2. Distributed Unmetered Load

124. Distributed Unmetered Load (DUML) is defined in the Code as “unmetered load with a single profile supplied to a single customer across more than one point of connection”.

Streetlights

125. The most significant forms of DUML are streetlights supplied for Local Authorities and the NZTA. These are for individual unmetered supplies for streetlights that surround local streets (Local Authorities) and State Highways (NZTA).

126. For streetlights connected to the South Dunedin and Halfway Bush GXPs, Aurora Energy applies a Daily Fixed Price for all connections connected to each GXP. For streetlight connections in Central Otago and Heritage Estate, a combination of a daily fixed price (on a per lamp basis) and volumetric prices are used to charge electricity retailers for these connections.

127. Aurora Energy’s GIS records the wattage and type of light for each streetlight connection on the network. We use the stored information in the GIS system, combined with the number of hours in the month where streetlights have been switched on, to calculate the total charges for each party’s streetlight connections.

128. Despite that our systems are used to record street light numbers and wattage; it is the customer's responsibility with correct information when assets are added or modified.

Other Distributed Unmetered Load (Dunedin only)

129. Aurora Energy offers separate DUML pricing to customers on the Dunedin network, as the pricing used for streetlights cannot be used for non-street light connections. In order to qualify for this pricing, a request for a DUML connection needs to be made by the customer or electricity retailer, with wattage and period of operation information for each individual unmetered connection.

130. Aurora Energy uses a combination of a daily fixed price (on a per ICP basis) and volumetric prices to charge electricity retailers for these connections.

131. Other DUML connections on the Central Otago and Heritage Estate networks will be charged according to the street light pricing plan.

4.2.3. Temporary Supply

132. Temporary supplies on the Aurora Energy network are most commonly used for construction supplies, where a connection is supplied to a worksite to provide electricity for builders' tools. When construction of the building is complete, the connection will often be converted into a permanent supply to the new building. Temporary supplies can be used for concert or other entertainment connections, where supply is required for a short period of time.

133. We charge a single daily fixed price for temporary supplies.

134. The installed capacity of an unmetered temporary supply must be 15kVA or less. Where the installed capacity of the connection is greater than 15kVA, the connection will be priced according to the relevant capacity-based pricing group and must be metered.

4.2.4. Capacity Based Pricing Groups

135. For General connections that do not meet the qualification criteria for Unmetered Load, DUML, or Temporary Supplies, they will be charged according to the relevant capacity pricing band. Sections 3.7.1 and 3.7.2 outline the applicable pricing for these connections.

5. Seasonal Loads

5.1. Background

136. Aurora Energy has 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.

137. We have 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), we have determined the following policy with respect to seasonal loads.

5.2. Delivery Pricing Recovery

138. Aurora Energy'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 not permitted.

5.3. Policy

139. 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 Energy is received;
- where disconnections occur for more than 12 months then we reserve 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; and
- the Reconnection Charge will be invoiced to the retailer that 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.

6. Other Pricing Considerations

140. Other considerations relevant to Aurora Energy's pricing methodology are:

- prices apply per ICP;
- 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;
- 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 HV metered installations; an additional charge will apply where Aurora Energy owns the transformers and associated HV switchgear;
- 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 Energy's website www.auroraenergy.co.nz; and
- prices exclude metering services involved with the provision of meters or meter reading. These services are provided by others.

141. The amounts budgeted for asset maintenance are detailed in Aurora Energy's Asset Management Plan under the following categories:

- system control;
- subtransmission lines and cables (66kV & 33 kV);
- zone substations (33 kV to 11 kV and 6.6 kV transformation);
- HV lines and cables (11 kV and 6.6 kV);
- distribution substations (11/6.6 kV to 400 V transformation); and
- LV lines and cables (400 V).

142. 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.

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

6.1. Non-standard Contracts

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

- the Assessed Capacity of the Customer's connections exceeds 1,000kVA;
- the customer's connection is dedicated;
- the customer's load profile is significantly different from comparable connections; and

- the customer can clearly demonstrate that continuation of standard arrangements is likely to result in inefficient outcomes.

145. Aurora Energy currently has two operative non-standard agreements, covering 9 ICPs. Aurora Energy expects to generate approximately 0.4% of target revenue ($0.4m) from these ICPs in the year to 31 March 2022.

146. Further details of non-standard contracts are available on the distributor agreement page of Aurora Energy's website (www.auroraenergy.co.nz).

147. We intend to review our approach towards non-standard contracts during the coming year to ensure alignment with the 2019 pricing principles.

7. Distributed Generation

148. This section outlines the methodology by which charges associated with the connection of DG are calculated.

149. This methodology applies to DG connected at HV only, and generally does not apply to generation connected behind load. In these cases, normal delivery prices apply according to the installation connection capacity.

7.1. General

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

- connection charges paid by the DG owner to Aurora Energy;
- recovery of HVDC Transmission Charges paid by the DG owner to Aurora Energy; and
- ACOT[6] payments by Aurora Energy to the DG owner.

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

152. SSDG 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 SSDG that forms part of a residential connection are able to avoid the full retail costs of energy (per unit), including the delivery prices.

153. The degree to which owners of SSDG forming part of a General connection receive benefits depends largely on the electricity retailer's offering; however, from Aurora Energy's perspective, these customers are able to avoid a significant proportion of the distribution and pass-through CPD prices.

7.2. Distributed Generation Connection Charge

154. The DG connection charge recovers costs associated with assets provided by Aurora Energy in the following situations:

- assets provided solely for the connection of the DG to the distribution network; and
- use of shared assets that are required due to the capacity required by the DG and which are in excess of that required for the local network.

The charge comprises three components:

- a return on investment;

6 Referred to in preceding sections as the Distributed Generation Allowance in accordance with regulatory terminology; however, in this section we have maintained the term ACOT as this more accurately conveys the basis of the charge to interested persons.

– depreciation; and
– maintenance costs.

7.2.1. Return on Investment (ROI)

155. Aurora Energy will value the assets used exclusively for conveying electricity produced by DG at 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.

156. In most circumstances, DG will be injected into Aurora Energy's sub-transmission network (33kV and 66kV); however, injection into Aurora Energy's 11kV distribution network may be possible.

157. Where generation specific sub-transmission circuits and lower voltage distribution circuits share the same structures, the value of the assets attributable to DG 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 DG (and hence the sub-transmission circuit) not existed, and the DRC of the existing under-built circuit.

158. Where multiple DG shares assets that Aurora Energy has provided exclusively for conveying electricity produced by DG, the return on investment price will be apportioned according to the ratio of the nameplate rating of the DG owner's plant to the sum of the total nameplate rating of all DG owners' plant utilising those shared assets.

159. Aurora Energy will provide an asset valuation table and, where multiple DG is involved, apportionment calculations as part of its contract with the DG owner.

7.2.2. Depreciation

160. Aurora Energy will value the assets used exclusively for conveying electricity produced by DG at Replacement Cost (RC). Depreciation will be calculated according to the standard lives for each appropriate asset class[7]. Accordingly, the calculation will be:

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

161. Where multiple DG shares assets that Aurora Energy has provided exclusively for conveying electricity produced by DG, the depreciation price will be apportioned according to the ratio of the nameplate rating of the DG owner's plant to the sum of the total nameplate rating of all DG owners' plant utilising those shared assets.

162. Aurora Energy will provide an asset valuation table, table of depreciation charges and, where multiple DG owners are involved, apportionment calculations, as part of its contract with the DG owner.

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

7.2.3. Maintenance

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

164. The maintenance price attributable to DG will be the ratio of the RC of assets that Aurora Energy has provided exclusively for conveying electricity produced by DG, to the RC of all assets of the same class in the same area.

Example:

165. Aurora Energy 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 DG owner 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.

166. The maintenance price of the Distribution Charge attributable to the DG is:

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

167. Where multiple DG shares assets that Aurora Energy has provided exclusively for conveying electricity produced by DG, the maintenance price will be apportioned according to the ratio of the nameplate rating of the DG owner's plant to the sum of the total nameplate rating of all DG owner's plant utilising those shared assets.

168. Aurora Energy will provide an asset valuation table, table of budgeted maintenance costs and, where multiple DG owners are involved, apportionment calculations, as part of its contract with the DG owner.

7.2.4. New Generation

169. Where new DG proposes to connect to shared assets that Aurora Energy has provided exclusively for conveying electricity produced by other DG owners, or an existing DG owner proposes to increase the amount of generation injected into the Aurora Energy 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 DG. In such circumstances, ROI, depreciation and maintenance charges associated with the additional assets or network reinforcement shall be attributed to the DG owner requiring the additional investment.

7.3. Connection Charge Adjustments

7.3.1. Inflation Adjustment

170. The DG 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.

7.3.2. Valuation Review

171. DG 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.

7.4. Transmission Related Transactions

172. Some DG has the ability to support Transpower in meeting its grid reliably standards, as defined in the Code. Transpower will periodically report the details of supportive generation to the EA who will, in turn, publish a list of DG that may be considered for ACOT payments under Schedule 6.4 of the Code (Qualifying DG).

173. Subject to:

- the value of ACOT being prescribed by Transpower or the EA; or
- the methodology for estimating ACOT being prescribed by Transpower or the EA,

Aurora Energy will estimate the value of ACOT for qualifying DG using the following methodology.

174. Aurora Energy will pay owners of Qualifying DG a proportion of the avoided Interconnection Charges created by their injection into Aurora Energy's network. The amount retained by Aurora Energy recognises that there are significant administration and data management costs associated with DG connections. The proportions paid are listed in Table 10

Table 10: Avoided transmission rate by generation capacity

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 DG is behind load. Half-hourly metering is a prerequisite.

175. Transpower sets its Interconnection Charge, for each GXP serving the Aurora Energy network, by multiplying its national Interconnection Rate (IR) $ per kW, by the average off-take demand occurring at the GXP during RCPD periods. The Interconnection Charge then applies during the following 1 April to 31 March period.

176. Aurora Energy calculates a Without Generation Interconnection Demand, based on the average system demand at each GXP of the Aurora Energy network during RCPD periods.

177. 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 ACOT payable by Aurora Energy to Qualifying DG owners.

178. Where there are multiple Qualifying DG owners operating in a GXP, then the Avoided Transmission Demand needs to be shared between those Qualifying DG owners. The Avoided Transmission

Demand will be allocated to each Qualifying DG owner based upon the ratio of their average generation (MW) to the total average DG (MW) during RCPD periods.

179. The ACOT paid to each Qualifying DG owner is calculated as:

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

where:

- ATR is the Avoided Transmission Rate according to figure 12.
- IC is the Interconnection Rate set annually by Transpower.

180. Since ACOT is based on historical data, Qualifying DG may not become eligible for avoided transmission payments until they have recorded injection into the Aurora Energy network during the CMP. Once injection is registered, ACOT Payments will be made to the Qualifying DG owner from the following April.

7.4.1. Recovery of HVDC Charges

181. Where net injection to the Grid occurs at a GXP serving the Aurora Energy network, Aurora Energy 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 Energy will recover the HVDC Charges from the DG owners that cause the charges to occur.

182. Transpower sets the SIMI portion of the HVDC Charges for each GXP serving the Aurora Energy network, by multiplying its SIMI Rate ($/MWh) by the SIMI recorded at the GXP. The SIMI Rate is calculated as the average total energy injected over a five-year period.

183. Where there are multiple DG owners operating in a GXP, the HVDC Charges need to be allocated to those DG owners. HVDC Charges will be allocated to each DG owner based upon the ratio of their generation production (MWh) to the total generation production (MWh) within the GXP during the CMP.

7.5. Current Prices

184. The current distributed generation prices are set out in Table 11.

Table 11: Distributed generation prices

Generation Details			Prices ($ per annum)		
Generator	GXP	Installed Capacity (MW)	Connection	ACOT	HVDC
Generator 1	HWB	75	$132,649	$4,600,023	$51,216
Generator 2	CYD	29.8	$385,239	$-	$198,818
Generator 2	CML	4.3	$55,203	$334,525	$-
Generator 2	FKN	2.1	$27,452	$139,326	$-
Generator 3	CYD	2.2	$27,939	$-	$18,962

8. Glossary

Abbreviation	Definition
ACOT	means Avoided Cost of Transmission
AMD	means Anytime Maximum Demand
ATR	means Avoided Transmission Rate
Capex	means Capital Expenditure
CMD	means Co-incident Maximum Demand
CML	means Cromwell
CMP	means Transpower's capacity measurement period, which for the purposes of calculating RCPD in the lower South Island, is the twelve months from 1 September to 31 August annually but excluding the summer months of November to April, inclusive
Code	means the Electricity Industry Participation Code
CPD	means Control Period Demand
CPI	means the Consumers' Price Index published by Statistics New Zealand
CPP	means Customised Pricing-quality Path
CRP	means Cost-Reflective Pricing
DG	means Distributed Generation
DRC	means Depreciated Replacement Cost
DUML	means Distributed Unmetered Load
EA	means the Electricity Authority
EV	means Electric Vehicles
FENZ	means Fire Emergency New Zealand
GXP	means Grid Exit Point
HV	means High Voltage
HVDC	means High Voltage Direct Current
ICP	means Installation Control Point, and is further defined in the Code
IR	means Interconnection Rate
IRIS	means Incremental Rolling Incentive Scheme
km	means kilometre
kVA	means kilovolt-ampere
kW	means kilowatt

Abbreviation	Definition
kWh	means kilowatt Hour
LPG	means Liquid Petroleum Gas
LRMC	means Long-Run Marginal Cost
LV	means Low Voltage
Opex	means Operating Expenditure
RAB	means Regulatory Asset Base
RC	means Replacement Cost
RCPD	means Regional Coincident Peak Demand which, in the case of the lower South Island, is the top 100 half-hourly peaks during Transpower's CMP
ROI	means Return on Investment
SCADA	means Supervisory Control and Data Acquisition
SIMI	means South Island Mean Injection
SONS	means System Operations and Network Support
SSDG	means Small-scale Distributed Generation
TOU	Means Time-of-Use Pricing

Appendix A. PRICE SCHEDULES

SCHEDULE A DUNEDIN PRICING AREA

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	9.53	0.46	9.99	¢/kWh
Uncontrolled - Winter	010	10.88	4.37	15.25	¢/kWh
All Inclusive - Summer [1]	017	4.70	1.29	5.99	¢/kWh
All Inclusive - Winter [1]	017	6.97	1.87	8.84	¢/kWh
Controlled	006	3.00	0.80	3.80	¢/kWh
Night Boost	024	2.44	0.66	3.10	¢/kWh
Night Only	028	0.65		0.65	¢/kWh
All Inclusive - Summer Day [1]	011	8.72	0.15	8.87	¢/kWh
All Inclusive - Winter Day [1]	011	9.26	4.09	13.35	¢/kWh
All Inclusive - Summer Night [1]	012	0.65		0.65	¢/kWh
All Inclusive - Winter Night [1]	012	0.65		0.65	¢/kWh

A2. General Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Street Lighting Price Components					
Daily Fixed Price (SDN)	SDNSTL	407.20	69.65	476.85	$/ICP/day
Daily Fixed Price (HWB)	HWBSTL	800.37	53.84	854.21	$/ICP/day
Distributed Unmetered Load (DUML) Price Components					
Daily Fixed Price	SHSUNM	6.12		6.12	¢/ICP/day
Volumetric Price	030	2.18	0.59	2.77	¢/kWh
Load Group 0 (Unmetered Supply <1kVA Capacity) Price Components					
Daily Fixed Price	SH0	49.83	7.24	57.07	¢/day
Load Group 0A (Temporary Connection) Price Components					
Daily Fixed Price	SH0A	103.46	19.52	122.98	¢/day
Load Group 1A (≤8kVA Capacity) Price Components					
Daily Fixed Price	SH1A	4.61		4.61	¢/day
Capacity Price	SH1A	6.35	-0.99	5.36	¢/kVA/day
CPD Price	SH1A	37.73	28.17	65.90	¢/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	4.61		4.61	¢/day
Capacity Price	SH1	5.67	-0.70	4.97	¢/kVA/day
CPD Price	SH1	37.73	28.17	65.90	¢/kW/day
Load Group 2 (16-149kVA Capacity) Price Components					
Daily Fixed Price	SH2	9.52		9.52	¢/day
Capacity Price	SH2	6.91	-1.81	5.10	¢/kVA/day
CPD Price	SH2	37.73	28.17	65.90	¢/kW/day
Load Group 3 (150-249kVA Capacity) Price Components					
Daily Fixed Price	SH3	171.70		171.70	¢/day
Capacity Price	SH3	11.61	-3.22	8.39	¢/kVA/day
Distance Price	SH3	0.11		0.11	¢/kVA-km/day
CPD Price	SH3	25.50	27.95	53.45	¢/kW/day
Load Group 3A (250-499kVA Capacity) Price Components					
Daily Fixed Price	SH3A	171.70		171.70	¢/day
Capacity Price	SH3A	10.45	-3.22	7.23	¢/kVA/day
Distance Price	SH3A	0.11		0.11	¢/kVA-km/day
CPD Price	SH3A	25.50	27.95	53.45	¢/kW/day
Load Group 4 (500-2,499kVA Capacity) Price Components					
Daily Fixed Price	SH4	448.35		448.35	¢/day
Capacity Price	SH4	5.70	-0.70	5.00	¢/kVA/day
Distance Price	SH4	0.11		0.11	¢/kVA-km/day
CPD Price	SH4	21.86	27.95	49.81	¢/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	448.35		448.35	¢/day
Capacity Price	SH5	3.82	-0.87	2.95	¢/kVA/day
Distance Price	SH5	0.11		0.11	¢/kVA-km/day
CPD Price	SH5	14.03	27.95	41.98	¢/kW/day
Equipment Price (if applicable)	SH5	70.00		70.00	¢/kVA/mth

SCHEDULE B CENTRAL OTAGO / WANAKA PRICING AREA

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	12.97	-0.69	12.28	¢/kWh
Uncontrolled - Winter	101	17.93	-0.46	17.47	¢/kWh
Controlled (20hr)	109	9.46	-0.33	9.13	¢/kWh
Controlled (16hr)	106	6.85	-0.21	6.64	¢/kWh
Night Boost (13hr)	103	7.70	-0.27	7.43	¢/kWh
Night Boost (11hr)	104	6.30	-0.22	6.08	¢/kWh
Night Only	108	5.39		5.39	¢/kWh

B2. General Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Street Lighting Price Components					
Daily Fixed Price	CCSTL	3.76		3.76	¢/lamp/day
Volumetric Price	110	5.14	0.10	5.24	¢/kWh
Load Group 0 (Unmetered Supply <1kVA Capacity) Price Components					
Daily Fixed Price	CC0	67.50	-8.50	59.00	¢/day
Load Group 0A (Temporary Connection) Price Components					
Daily Fixed Price	CC0A	128.71	-17.38	111.33	¢/day
Load Group 1A (≤8kVA Capacity) Price Components					
Daily Fixed Price	CC1A	4.75		4.75	¢/day
Capacity Price	CC1A	8.71	-1.43	7.28	¢/kVA/day
CPD Price	CC1A	60.06	27.34	87.40	¢/kW/day
Load Group 1 (≤15kVA Capacity) Price Components					
Daily Fixed Price	CC1	4.75		4.75	¢/day
Capacity Price	CC1	6.69	-2.10	4.59	¢/kVA/day
CPD Price	CC1	60.06	27.34	87.40	¢/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	9.90		9.90	¢/day
Capacity Price	CC2	8.57	-1.95	6.62	¢/kVA/day
CPD Price	CC2	52.37	20.13	72.50	¢/kW/day
Load Group 3 (150-249kVA Capacity) Price Components					
Daily Fixed Price	CC3	189.95		189.95	¢/day
Capacity Price	CC3	8.66	-2.50	6.16	¢/kVA/day
Distance Price	CC3	0.13		0.13	¢/kVA-km/day
CPD Price	CC3	55.60	17.32	72.92	¢/kW/day
Load Group 3A (250-499kVA Capacity) Price Components					
Daily Fixed Price	CC3A	189.95		189.95	¢/day
Capacity Price	CC3A	8.62	-2.50	6.12	¢/kVA/day
Distance Price	CC3A	0.13		0.13	¢/kVA-km/day
CPD Price	CC3A	55.60	17.32	72.92	¢/kW/day
Load Group 4 (500-2,499kVA Capacity) Price Components					
Daily Fixed Price	CC4	498.48		498.48	¢/day
Capacity Price	CC4	9.27	-2.46	6.81	¢/kVA/day
Distance Price	CC4	0.13		0.13	¢/kVA-km/day
CPD Price	CC4	49.62	17.32	66.94	¢/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	498.48		498.48	¢/day
Capacity Price	CC5	6.19	-2.57	3.62	¢/kVA/day
Distance Price	CC5	0.13		0.13	¢/kVA-km/day
CPD Price	CC5	49.62	17.32	66.94	¢/kW/day
Equipment Price (if applicable)	CC5	70.00		70.00	¢/kVA/mth

SCHEDULE C QUEENSTOWN PRICING AREA

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	8.80	0.34	9.14	¢/kWh
Uncontrolled - Winter	201	10.71	3.64	14.35	¢/kWh
Controlled (20hr)	209	5.06	1.15	6.21	¢/kWh
Controlled (16hr)	206	2.25	0.52	2.77	¢/kWh
Night Boost (13hr)	203	3.31	0.75	4.06	¢/kWh
Night Boost (11hr)	204	2.02	0.47	2.49	¢/kWh
Night Only	208	1.44		1.44	¢/kWh

C2. General Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Street Lighting Price Components					
Daily Fixed Price	FRSTL	3.94		3.94	¢/lamp/day
Volumetric Price	210	1.39	0.33	1.72	¢/kWh
Load Group 0 (Unmetered Supply <1kVA Capacity) Price Components					
Daily Fixed Price	FR0	44.41	20.10	64.51	¢/day
Load Group 0A (Temporary Connection) Price Components					
Daily Fixed Price	FR0A	80.45	47.76	128.21	¢/day
Load Group 1A (≤8kVA Capacity) Price Components					
Daily Fixed Price	FR1A	4.19		4.19	¢/day
Capacity Price	FR1A	5.56	-1.31	4.25	¢/kVA/day
CPD Price	FR1A	26.30	24.68	50.98	¢/kW/day
Load Group 1 (≤15kVA Capacity) Price Components					
Daily Fixed Price	FR1	4.19		4.19	¢/day
Capacity Price	FR1	5.21	-1.31	3.90	¢/kVA/day
CPD Price	FR1	26.30	24.68	50.98	¢/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	6.54		6.54	¢/day
Capacity Price	FR2	6.27	-1.41	4.86	¢/kVA/day
CPD Price	FR2	31.29	26.86	58.15	¢/kW/day
Load Group 3 (150-249kVA Capacity) Price Components					
Daily Fixed Price	FR3	151.70		151.70	¢/day
Capacity Price	FR3	14.78	-1.33	13.45	¢/kVA/day
Distance Price	FR3	0.11		0.11	¢/kVA-km/day
CPD Price	FR3	20.12	16.91	37.03	¢/kW/day
Load Group 3A (250-499kVA Capacity) Price Components					
Daily Fixed Price	FR3A	151.70		151.70	¢/day
Capacity Price	FR3A	13.51	-1.33	12.18	¢/kVA/day
Distance Price	FR3A	0.11		0.11	¢/kVA-km/day
CPD Price	FR3A	20.12	16.91	37.03	¢/kW/day
Load Group 4 (500-2,499kVA Capacity) Price Components					
Daily Fixed Price	FR4	398.73		398.73	¢/day
Capacity Price	FR4	7.34	-0.03	7.31	¢/kVA/day
Distance Price	FR4	0.11		0.11	¢/kVA-km/day
CPD Price	FR4	23.21	16.91	40.12	¢/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	398.73		398.73	¢/day
Capacity Price	FR5	1.75	-0.13	1.62	¢/kVA/day
Distance Price	FR5	0.11		0.11	¢/kVA-km/day
CPD Price	FR5	15.95	16.91	32.86	¢/kW/day
Equipment Price (if applicable)	FR5	70.00		70.00	¢/kVA/mth

Schedule D Queenstown Pricing Area (Frankton 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	8.80	0.34	9.14	¢/kWh
Uncontrolled - Winter	301	10.71	3.64	14.35	¢/kWh
Controlled (20hr)	309	5.06	1.15	6.21	¢/kWh
Controlled (16hr)	306	2.25	0.52	2.77	¢/kWh
Night Boost (13hr)	303	3.31	0.75	4.06	¢/kWh
Night Boost (11hr)	304	2.02	0.47	2.49	¢/kWh
Night Only	308	1.44		1.44	¢/kWh

D2. General Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Street Lighting Price Components					
Daily Fixed Price	FKSTL	3.94		3.94	¢/lamp/day
Volumetric Price	310	1.39	0.33	1.72	¢/kWh
Load Group 0 (Unmetered Supply <1kVA Capacity) Price Components					
Daily Fixed Price	FK0	44.41	20.10	64.51	¢/day
Load Group 0A (Temporary Connection) Price Components					
Daily Fixed Price	FK0A	80.45	47.76	128.21	¢/day
Load Group 1A (≤8kVA Capacity) Price Components					
Daily Fixed Price	FK1A	4.19		4.19	¢/day
Capacity Price	FK1A	5.56	-1.31	4.25	¢/kVA/day
CPD Price	FK1A	26.30	24.68	50.98	¢/kW/day
Load Group 1 (≤15kVA Capacity) Price Components					
Daily Fixed Price	FK1	4.19		4.19	¢/day
Capacity Price	FK1	5.21	-1.31	3.90	¢/kVA/day
CPD Price	FK1	26.30	24.68	50.98	¢/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	5.96		5.96	¢/day
Capacity Price	FK2	5.72	-1.41	4.31	¢/kVA/day
CPD Price	FK2	28.51	26.86	55.37	¢/kW/day
Load Group 3 (150-249kVA Capacity) Price Components					
Daily Fixed Price	FK3	123.83		123.83	¢/day
Capacity Price	FK3	12.07	-1.33	10.74	¢/kVA/day
Distance Price	FK3	0.11		0.11	¢/kVA-km/day
CPD Price	FK3	16.43	16.91	33.34	¢/kW/day
Load Group 3A (250-499kVA Capacity) Price Components					
Daily Fixed Price	FK3A	123.83		123.83	¢/day
Capacity Price	FK3A	11.04	-1.33	9.71	¢/kVA/day
Distance Price	FK3A	0.11		0.11	¢/kVA-km/day
CPD Price	FK3A	16.43	16.91	33.34	¢/kW/day
Load Group 4 (500-2,499kVA Capacity) Price Components					
Daily Fixed Price	FK4	305.52		305.52	¢/day
Capacity Price	FK4	5.64	-0.03	5.61	¢/kVA/day
Distance Price	FK4	0.11		0.11	¢/kVA-km/day
CPD Price	FK4	17.81	16.91	34.72	¢/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	305.52		305.52	¢/day
Capacity Price	FK5	1.18	-0.13	1.05	¢/kVA/day
Distance Price	FK5	0.11		0.11	¢/kVA-km/day
CPD Price	FK5	12.24	16.91	29.15	¢/kW/day
Equipment Price (if applicable)	FK5	70.00		70.00	¢/kVA/mth

SCHEDULE E TE ANAU EMBEDDED NETWORK

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	11.15		11.15	¢/kWh
Uncontrolled - Winter	401	16.76		16.76	¢/kWh
Controlled	406	5.21		5.21	¢/kWh
Night Boost	404	4.61		4.61	¢/kWh
Night Only	408	3.07		3.07	¢/kWh
E2. General Connections	**Code**	**(D) Distribution**	**(P) Pass-through**	**(D + P) Delivery**	**Units**
Street Lighting Price Components					
Daily Fixed Price	HESTL	3.77		3.77	¢/lamp/day
Volumetric Price	410	7.20		7.20	¢/kWh
Load Group 0 (Unmetered Supply <1kVA Capacity) Price Components					
Daily Fixed Price	HE0	63.39		63.39	¢/day
Load Group 0A (Temporary Connection) Price Components					
Daily Fixed Price	HE0A	130.92		130.92	¢/day
Load Group 1A (≤8kVA Capacity) Price Components					
Daily Fixed Price	HE1A	3.17		3.17	¢/day
Capacity Price	HE1A	7.41		7.41	¢/kVA/day
CPD Price	HE1A	69.47		69.47	¢/kW/day
Load Group 1 (≤15kVA Capacity) Price Components					
Daily Fixed Price	HE1	3.17		3.17	¢/day
Capacity Price	HE1	7.12		7.12	¢/kVA/day
CPD Price	HE1	69.47		69.47	¢/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	6.68		6.68	¢/day
Capacity Price	HE2	6.22		6.22	¢/kVA/day
CPD Price	HE2	67.13		67.13	¢/kW/day

Appendix B. 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 Energy 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 Energy 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 Queenstown sub area is defined by Aurora Energy 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 Energization Date of 1 April 2017, or any later date.
17. Excess capacity charges of $8.40 per kVA will be charged to customers supplied by a dedicated transformer where they subsequently reduce their Assessed Capacity. The customer can avoid the excess capacity charges if they arrange for the transformer to be physically downsized.

Appendix C. 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

Appendix D. Alignment to Pricing Principles

Below we review our pricing for alignment with the Electricity Authority's 2019 pricing principles. For each principle, we summarise our interpretation, assess current alignment and assess how alignment will improve as we implement our strategy.

D.1. Cost Signalling

There are four principles focussed on aspects of cost signalling.

D.1.1. Subsidy Free

(a)	Prices are to signal the economic costs of service provision, including by:	
	(i)	being subsidy free (equal to or great than avoidable costs, and less than or equal to standalone costs)

Interpretation

Subsidy-free pricing ensures no group of customers is worse-off through being part of a shared network. Subsidy-free is a range, rather than a single value, and can be assessed between different groupings of customers. The most pertinent groupings for us are:

- between pricing areas; and
- between consumer groups within each pricing area.

We do not use the term *consumer group* at present, but it is equivalent to our load groups plus further splitting LG1 into residential and non-residential.

Avoidable costs can be assessed in terms of *short run* avoidable costs (e.g., some portion of opex) or *total* avoidable costs (i.e., the capital and operating costs that would be avoided if the consumer group never existed). The latter provides a more complete measure of whether a consumer group's contribution to revenue is subsidy-free over time.

Standalone costs can be assessed in terms of *non-network* solutions (i.e., the lowest-cost off-grid solution) or the cost of a standalone network (i.e., a network built only for one consumer group). Selecting the lower of these two values provides the best measure of whether prices are subsidy free.

Testing for subsidy at the pricing area and consumer group area is not intended to guarantee there are no subsidies between individual customers – e.g., a remote rural customer may still pay less than their standalone cost.

Assessment

Table 12 assesses current (RY23) alignment, and how that will change as we implement our strategy and move toward our target pricing arrangements.

Table 12: Subsidy free assessment

Element	Current	Target
Subsidy-free pricing areas	We attribute capital costs using estimated replacement cost values and using a mix of proxy allocators for opex. This results in each pricing area covering its direct costs and making some contribution to shared costs.	RAB-based allocation of capital costs and improved opex proxies will provide more robust cost allocation. This will further enhance confidence that prices are well within subsidy-free bands.
Subsidy-free consumer groups	We have estimates for short-run avoidable costs and non-network standalone costs. These provide a partial picture of the subsidy free range. Pricing for each load group is within the assessed range.	We will develop more complete estimates of the subsidy-free ranges at a consumer group level. As we rebalance pricing levels, we will ensure revenue from each consumer group falls within the range.

D.1.2. Economic Costs

(a) Prices are to signal the economic costs of service provision, including by:

(i) ...

(ii) reflecting the impacts of network use on economic costs

Interpretation

The dominant economic cost impacted by network use is the cost of expanding capacity to meet growth in peak demand. This includes LV, HV distribution and grid connection investment, as well as deeper grid reinforcement.

Capacity is added to meet peak demand, so we can reflect these economic costs by structuring prices so that people pay more for usage that contributes to peak demand. Provided there is ample capacity headroom, off-peak demand makes almost no contribution to capacity investment, so we can reflect this by structuring prices so that people pay very little for off-peak usage.

Managing load may (depending on the circumstances) mitigate the risk of that load contributing to network investment pressures. We can reflect this by reducing (or eliminating) peak charges for managed load.

Other economic costs we could reflect in prices include:

- connection capacity – the capacity of a connection may influence network reinforcement. This can be reflected in capital contribution rules and through capacity charges;
- injection capacity – high levels of injection (such as from rooftop solar) could drive a need for network investment, which could be reflected in an injection charge; and
- power factor – loads with a low power factor can reduce the efficiency of real power transfer, which could be reflected in kVAr charge.

In all cases, the aim is to signal how usage impacts future costs (i.e., costs that are not already sunk or historical).

Assessment

Table 13: Economic cost signalling assessment

Element	Current	Target
Economic cost signalling	We provide some signalling through summer vs. winter rates, night rates, and controlled rates for small consumers. For large consumers, we provide some signalling through capacity prices, control period demand prices and corrective capacitance charges. Our capital contributions policy also provides some signalling at the time of installation (or upgrade).	We aim to improve the targeting of our peak pricing periods, and better calibrate signal strength based on LRMC studies. Improved calibration will apply across peak, off-peak, and managed load discounts. We may also consider an injection charge if the LRMC is strong enough to warrant this step.

D.1.3. Services

(a) Prices are to signal the economic costs of service provision, including by:

(i) ...

(ii) ...

(iii) reflecting differences in network service provided to (or by) consumers

Interpretation

Service-based pricing could be relevant where customers can opt to receive a materially different level of service, with a materially different cost of supply. For example (and hypothetically):

- priority service – customers in an area of the network pay extra to gain priority access to restoration or backup supply services in the event of a fault;
- thin connection – a group of customers with their own back-up arrangements pay less in return for lower priority restoration, or greater exposure to load shedding; and
- network support – a generator or battery owner (utility scale or aggregated) receives a discount (or payments) in return for providing network support services.

Assessment

Table 14: Service based pricing assessment

Element	Current	Target
Service-based pricing	Like most electricity networks, we do not currently offer options for differentiated service levels. Our capital contributions policy encourages customers to make their own trade-offs where relevant.	No change.

D.1.4. Network Alternatives

(a)	Prices are to signal the economic costs of service provision, including by:	
	(i)	…
	(ii)	…
	(iii)	…
	(iv)	encouraging efficient network alternatives.

Interpretation

There are three ways pricing can play a role in encouraging efficient network alternatives:

- *ex ante* (before the fact) – capacity – if price structures and levels signal the cost of network expansion, then this can guide efficient choices about network alternatives. In other words, efficient pricing helps customers make their own choices and trade-offs between taking or avoiding network services;
- *ex post* (after the fact) – capacity – we may proactively encourage a transmission alternative as an option for addressing an emerging capacity or security constraint. As part of this, we may set specific prices for supplying those services; and
- *ex ante* – coverage – subsidy-free pricing helps potential customers determine whether they are better to fully self-supply. This is relevant to annual charges, and up-front capital contributions for new connections.

Assessment

Table 15: Network alternatives assessment

Element	Current	Target
Network alternatives	We provide some signalling through our current pricing but targeting and calibration could be improved. We are putting in place specific pricing arrangements as part of a tactical network alternatives trial in the upper part our Clutha network.	Improved targeting and calibration at a pricing area level.

D.2. Residual Costs

(b)	Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.

Interpretation

Prices designed to signal future economic costs and influence behaviour are unlikely to recover sufficient revenue to cover current costs. For this 'residual' revenue, the aim is to avoid influencing behaviour.

There are two aspects to residual charge design:

- allocation – in theory, residual costs are best allocated to consumer groups whose usage is least sensitive to overall cost. However, this is difficult to assess in practice and sensitivity varies across individuals within each consumer group; and
- structure – in theory, fixed charges are best for recovering revenue without influencing behaviour. A low variable charge spread evenly across all consumption can also work well, as can a mix of fixed and low variable charges.

Assessment

Table 16: Residual costs recovery assessment

Element	Current	Target
Residual	We set a low fixed charge for all residential consumers. This means usage-based charges are relatively high for those customers, including outside times when it would be useful to signal economic costs. For other consumer groups, we have a mix of usage-based (such as $ per kWh and $ per kW) and fixed components (such as $ per day, $ per kVA of connection capacity). Across all customers, around 70% of our revenue is recovered through usage-based charge components.	We will have usage-based charges structured to signal modelled LRMC, and we will have a more complete view of subsidy-free ranges. This will help ensure that the residual is not too big or too small and will help guide allocation between consumer groups. We expect that we will primarily recover allocated residual costs through fixed charges, though may supplement these with low and broad usage charges.

D.3. Negotiation

(c) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:

(i) reflect the economic value of services; and

(ii) enable price/quality trade-offs.

Interpretation

There are two circumstances where these principles come into play:

- existing customer – an existing customer may claim that their charges exceed the economic value of the services they receive – for example, because the charges make their operations unviable or because they have a viable (and cheaper) alternative option; and
- prospective customers – a customer seeking a new or upgraded connection may find that the combination of capital contribution and ongoing charges is uneconomic for them, or that they would prefer a non-standard level of service at a different price point.

Assessment

Table 17: Responsiveness assessment

Element	Current	Target
Responsiveness	We offer individual pricing for large customers with specialised needs. This allows scope for price-quality trade-offs. We have adjusted our prices for large customers in Frankton who may otherwise opt for uneconomic bypass.	We expect to retain these existing features. We aim to develop a more complete view of subsidy-free values, which will assist with ensuring (at a consumer group level) that prices are above avoidable cost and below standalone cost.

D.4. DEVELOPMENT

(d) Development of prices should be transparent and have regard to transaction costs, consumer impacts and uptake incentives.

Interpretation

This principle applies to our ongoing reform of pricing, including:

- transparency – do we provide clear information on how pricing works, our plans and rationale for change, and the likely impact on customers?
- transaction costs – will change be difficult or costly for retailers to implement and our customers to understand and (to the extent relevant) operationalise?
- consumer impacts – will change cause bill shock, volatility, or unpredictability for customers?; and
- uptake incentives – is reform designed to mitigate adverse selection problems and enable and encourage uptake of new pricing options?

Assessment

Table 18: Development assessment

Element	Assessment
Transparency	We publish our methodology and this year we are publishing our strategy and pricing roadmaps. We have also made improvements to our methodology document this year.
Transaction costs	We are aiming to simplify and reduce the number of price components and metrics we use. TOU pricing is more complex than our existing pricing, so communicating how it works, and when peak and off-peak periods are, will be important. We plan to consult on price components, including the best option for larger consumers that balances complexity and efficiency. We plan to consult once per year as we implement reform over the next few years.
Consumer impacts	We will inform our reform efforts through consultation, and analysis. We plan to introduce a mild form of TOU pricing initially and then gradually tune the signalling. This will soften year-on-year movement in pricing and support familiarisation.

Element	Assessment
Uptake incentives	TOU pricing has been implemented by several distributors now, and uptake amongst retailers is improving. We intend to explore options for accommodating consumers who do not have suitable metering while nonetheless encouraging uptake.

Appendix E. Compliance Matrix

This schedule demonstrates how this Use-of-System Pricing Methodology complies with the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 (consolidated April 2018).

Information Disclosure Requirement	Determination Reference	Pricing Methodology Reference
Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which –	Clause 2.4.1	
Describes the methodology, in accordance with clause 2.4.3, used to calculate the prices payable or to be payable;	Clause 2.4.1(1)	Section 3
Describes any changes in prices and target revenues;	Clause 2.4.1(2)	Section 3.4
Explains, in accordance with clause 2.4.5, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any);	Clause 2.4.1(3)	Sections 6.1 and 7
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 3.1
Every disclosure under clause 2.4.1 above must-	Clause 2.4.3	
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)	Sections 3.5 to 3.7
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)	Appendix D
State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	Clause 2.4.3(3)	Section 3.4

Information Disclosure Requirement	Determination Reference	Pricing Methodology Reference
Where applicable, identify the key tariffs 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 tariffs;	Clause 2.4.3(4)	Section 3.7 and Appendix A
State the consumer groups for whom prices have been set, and describe-	Clause 2.4.3(5)	Section 3.6
the rationale for grouping consumers in this way;	Clause 2.4.3(5)(a)	Section 3.6
the method and the criteria used by the EDB to allocate consumers to each of the consumer groups;	Clause 2.4.3(5)(b)	Section 3.6
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 3.4
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 3.6
State the proportion of target revenue (if applicable) that is collected through each price tariff as publicly disclosed under clause 2.4.18.	Clause 2.4.3(8)	Section 3.7
Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy-	Clause 2.4.4	
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 2
Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy;	Clause 2.4.4(2)	Section 2.8
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 1.2
Every disclosure under clause 2.4.1 above must:	Clause 2.4.5	
Describe the approach to setting prices for non-standard contracts, including-	Clause 2.4.5(1)	Section 6.1

Information Disclosure Requirement	Determination Reference	Pricing Methodology Reference
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 6.1
how the EDB determines whether to use a non-standard contract, including any criteria used;	Clause 2.4.5(1)(b)	Section 6.1
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 6.1
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-	Clause 2.4.5(2)	
the extent of the differences in the relevant terms between standard contracts and non-standard contracts;	Clause 2.4.5(2)(a)	Section 6.1
any implications of this approach for determining prices for consumers subject to non-standard contracts;	Clause 2.4.5(2)(b)	Section 6.1
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 7
prices; and	Clause 2.4.5(3)(a)	Section 7.5
value, structure and rationale for any payments to the owner of the distributed generation.	Clause 2.4.5(3)(b)	Section 7.4

Appendix F. Directors' Certificate

SCHEDULE 17[8]

Certification for Year-beginning Disclosures

(Pricing Methodology Only)

Clause 2.9.1 of section 2.9

We Stephen Richard Thompson and Margaret Patricia Devlin, being directors of Aurora Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Aurora Energy Limited prepared for the purposes of clause 2.4.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

Stephen Richard Thompson

Margaret Patricia Devlin

30 April 2021

8 Electricity Distribution Information Disclosure Determination 2012.

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