PRICING METHODOLOGY

1 April 2024

Aurora ENERGY

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1. Introduction

1.1. Preliminary

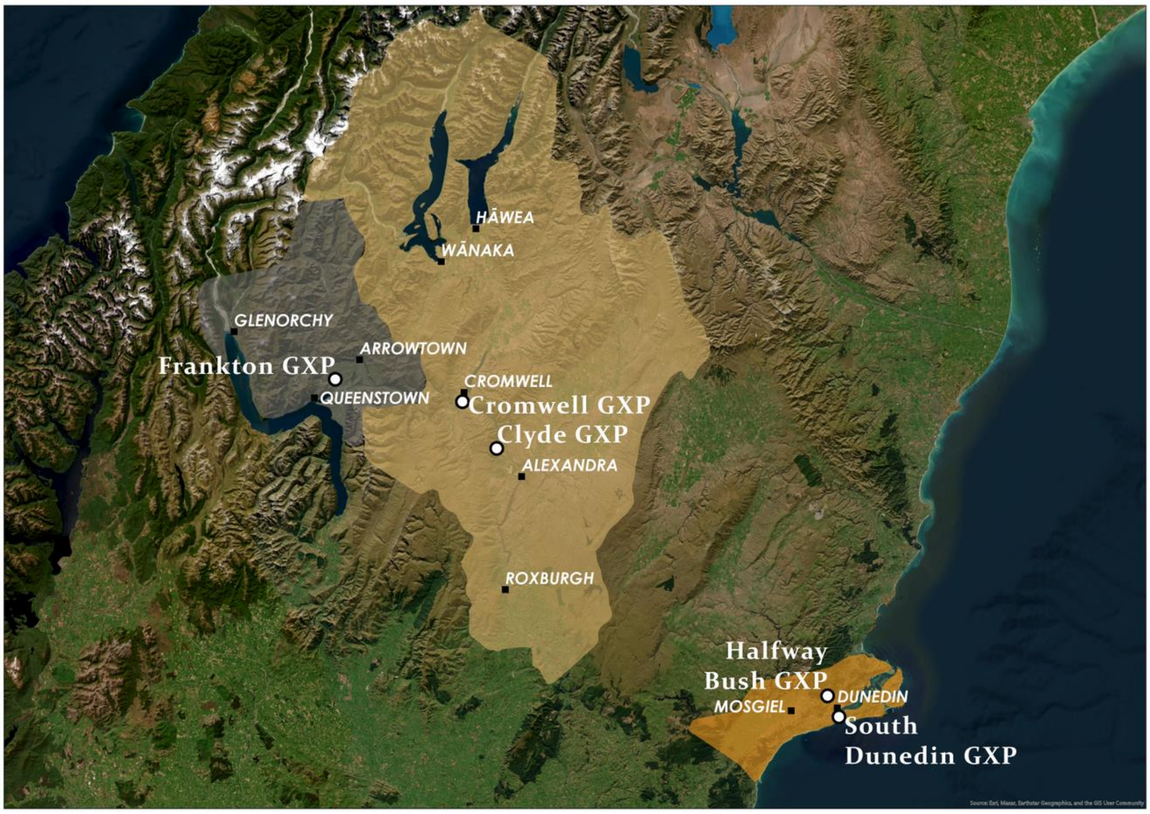
1. As a supplier of an essential service, Aurora Energy intend to set fair and reasonable prices for small, large and seasonal electricity users that have shared access to the network. This document outlines the pricing methodology Aurora Energy uses to determine its delivery prices.

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 Grid Exit Points (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. 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. In March 2021, the Commission published its final decision on the CPP application, including a schedule of forecast net allowable revenue for the five years from 1 April 2021 to 31 March 2026.

6. In April 2021, Aurora Energy published and consulted on the five-year pricing strategy and roadmap for pricing improvements to prepare for the significant electrification expected as New Zealand pursues its decarbonisation goals.

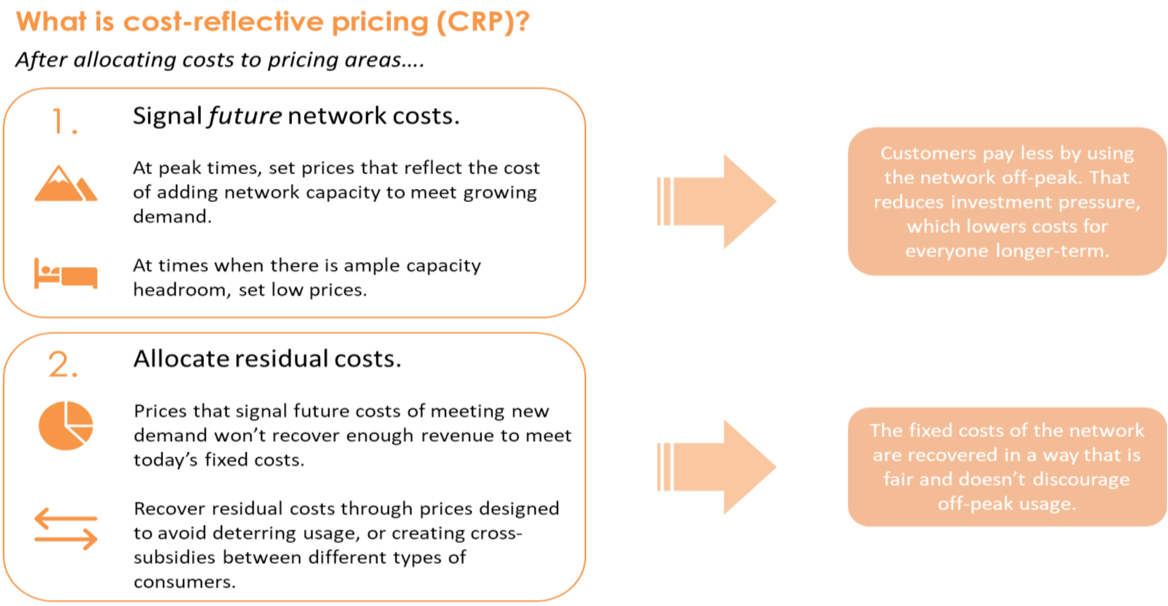
7. Section 2 of this document details the pricing strategy and roadmap, and section 3 outlines the progress made in the past year and the consequential implications for pricing from 1 April 2024.

2. Pricing Strategy

2.1. Overview

8. Technology changes, such as more affordable small-scale distributed generation 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



9. 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 consumers.

10. Transitioning to CRP is a major shift that will take time to implement. Aurora Energy is following a six-step approach to guide the transition:

    10.1. **Refine allocation to pricing areas** – this was the first priority to address an area of heightened community interest identified during the CPP application process. In 2021, refinements were made to the way operational costs are allocated, and following customer consultation, refinements have been made to the way capital investment-related costs are allocated to each pricing area. These changes were reflected in the prices which applied from 1 April 2022. This step is now complete.

    10.2. **Develop economic cost estimates –** to implement CRP, we had to develop sound estimates of the long-run marginal cost of supply (LRMC) in each of the pricing areas.

This work has now been completed and will form the basis for setting Time-of-Use (ToU) tariffs and Control tariffs in the future.

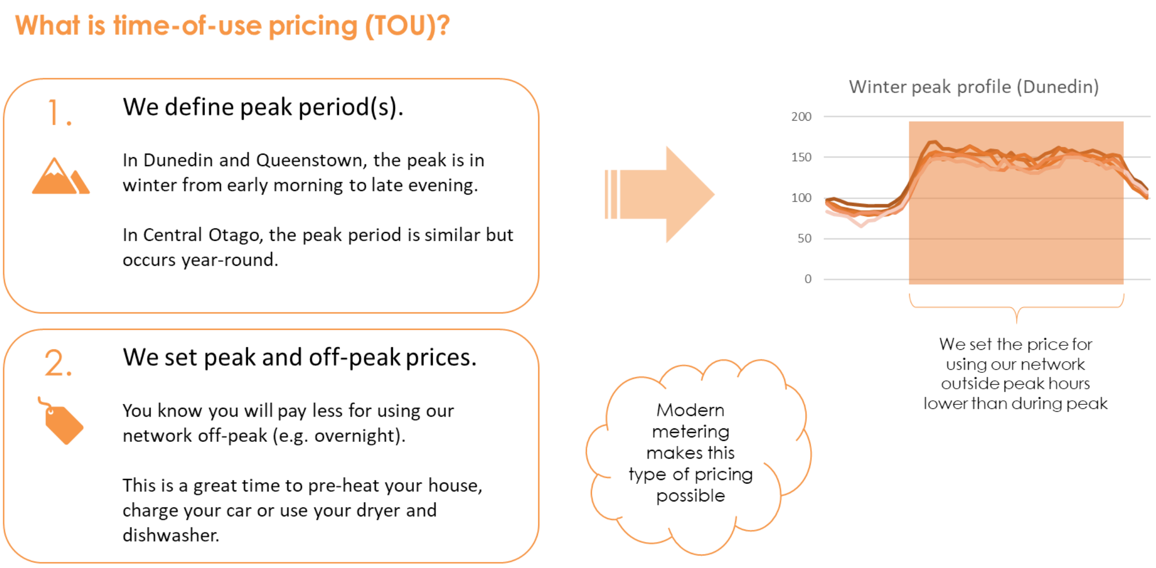
10.3. **Reform pricing structures** – for residential customers, we think ToU pricing (see Figure 3) is the best structure. Each pricing area should have peak periods that target times of investment pressure. From April 2024 we will introduce a mild form of ToU for residential customers with a focus on defining the pricing structure and peak periods, rather than the strength of the price signal. From 2025 to 2027 we will refine the strength of the ToU pricing signals as we transition to ToU tariffs that are reflective of the LRMC estimates in each pricing area. For non-residential customers, we will consult on whether a more dynamic structure may be appropriate.

10.4. **Enhance controllability discounts** – Aurora Energy provide discounted prices now for managed hot water and space heating. The design of these discounts will need to be aligned with the new approach and explore the potential to extend them for managed EVs (and possibly other technologies) in the future.

10.5. **Simplify cost allocation within pricing areas** – much of the complexity in the current pricing arrangements comes from the way costs are allocated to load groups and tariffs. Aurora Energy intends to consult with customers about adopting a simpler approach.

10.6. **Implement gradually and carefully** – Aurora Energy want to avoid unnecessarily exacerbating the bill pressure on customers, on top of the CPP implementation work. Implementing pricing reform gradually and carefully will help Aurora Energy achieve this goal, while still being able to realise the longer-term benefits of CRP.

Figure 3: Time-of-use pricing



11. Sections 2.2 to 2.10 provide more information on the context for pricing reform, and on each element of the strategy. More information on the pricing strategy is available on the *Pricing Pages* of the Aurora Energy website (www.aurorenergy.co.nz).

2.2. Context

12. 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.

13. 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 beyond 2027. If not refined, 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 the Otago 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.

14. 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 is phasing out the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (LFC Regulations). This improves the 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).

15. Operationally, there is also scope to simplify pricing. The existing methodology focusses on allocation of current (not future) costs between customers. This drives complexity into the processes and pricing structures. The removal of winter rates and the consolidation of control tariffs in RY24 was our first simplification step and is consistent with our transition to cost-reflective pricing.

16. Finally, the CPP delivery and current economic conditions add to the context for pricing reform:
    - revenue path – we will continue to have a relatively steep revenue path in coming years as we scale up capability and address a backlog of investment in the network assets. This heightens the need to carefully manage any additional bill shock that could flow from pricing reform;
    - pricing areas – consultation undertaken as part of the CPP stimulated interest in how costs are allocated to pricing areas. This made reviewing regional cost allocation a logical first step for reform;
    - renewal focus – the CPP delivery plans focus on asset renewal in coming years, with a more tactical approach (where possible) to managing growth. This creates a window of opportunity to reform pricing before the investment focus returns to addressing growth pressures; and
    - economic uncertainty – the 2020-2022 international border closure had a sharp impact on communities. The future state of tourism and education remains uncertain, which is adding network demand uncertainty.
    - affordability – we are particularly mindful that current inflationary and interest rate pressures are impacting consumers. The current economic environment has reinforced the importance of our approach to transition to ToU pricing in a careful and gradual manner.
17. These factors shape the impetus for reform, and the direction of the reform strategy.

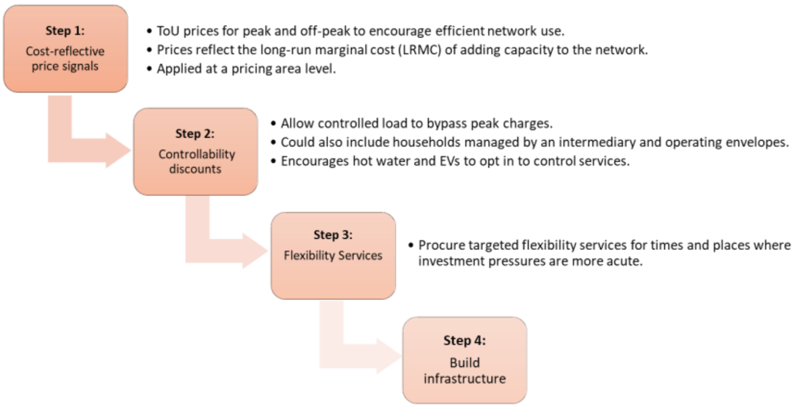
2.3. Objectives and Approach

18. Aurora Energy's aim is to optimise network investment, for the long-term benefit of consumers. We are entering a period where growing demand will intensify network investment pressures and it is important that Aurora Energy stay ahead of demand while not investing more than necessary.

19. Investing too little or too late reduces security and reliability. Investing too much or too early pushes up prices for consumers.

20. Alongside core asset management activities, Aurora Energy uses pricing and flexibility services[1] to help operate an efficient network. Figure 4 outlines the approach to responding to constraints on the network. Steps 1 and 2 rely on pricing signals to encourage consumers to shift demand to times when the network is less constrained. If pricing signals alone are insufficient to curb network demand, Aurora Energy will engage flexibility traders to help support the network (step 3). The final response to ongoing network constraints will be to invest in upgrading the network infrastructure.

Figure 4: Pricing Approach



[1] Flexible technologies like electric vehicles and solar can provide 'flexibility services' to electricity networks. By releasing power back to the grid at times of high demand, and storing it during times of lower demand, local 'flexibility services' unlock additional capacity and support the connection of more low-carbon technology such as solar.

2.4. Refine Allocations to Pricing Areas

COMPLETED 2022

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

22. The CPP stimulated interest in this process, from communities and regulators. Following a review commissioned by the Electricity Authority, Aurora Energy refined the allocation methodology for operating costs in RY22. Following further consultation with customers Aurora Energy moved to a Regulatory Asset Base (RAB) approach for allocating capital investment-related costs from RY23.
23. Section 3.5 of this document shows how these allocation methodologies are being used to allocate forecast allowable revenue for price-setting.

2.5. Develop Economic Cost Estimates

COMPLETED 2023

24. To implement CRP, Aurora Energy had 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 long-run marginal cost (LRMC) and will vary by pricing area and potentially, in the future, within pricing areas.

25. To estimate LRMC values, Aurora Energy developed a methodology and completed engineering studies. Section 4 of this document outlines our approach to calculating LRMC values for each of the pricing areas.

2.6. Reform Pricing Structures

26. Aurora Energy think ToU pricing is the most appropriate structure for residential 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.

27. To design appropriate ToU pricing, peak periods need to be set that correspond to times of network investment pressure and are simple enough for retailers to implement. Aurora Energy has considered these two objectives and determined it is most sensible to use the same peak periods across all of the pricing regions as follows:

    7am – 12pm (7 days per week) & 5pm – 10pm (7 days per week).

28. The peak periods selected are longer than most other electricity distributors in New Zealand, which reflects that the network is in a colder climate and typically has longer winter peaks than most other electricity distributors.

29. In April 2023 we simplified control tariffs for residential customers, removed seasonal tariff differences, and defined the residential ToU structure. From April 2024, we will introduce ToU price differentials to signal peak versus off-peak periods.

30. For commercial customers we are considering whether a form of ToU tariff may be best for smaller customers, and/or for larger 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.

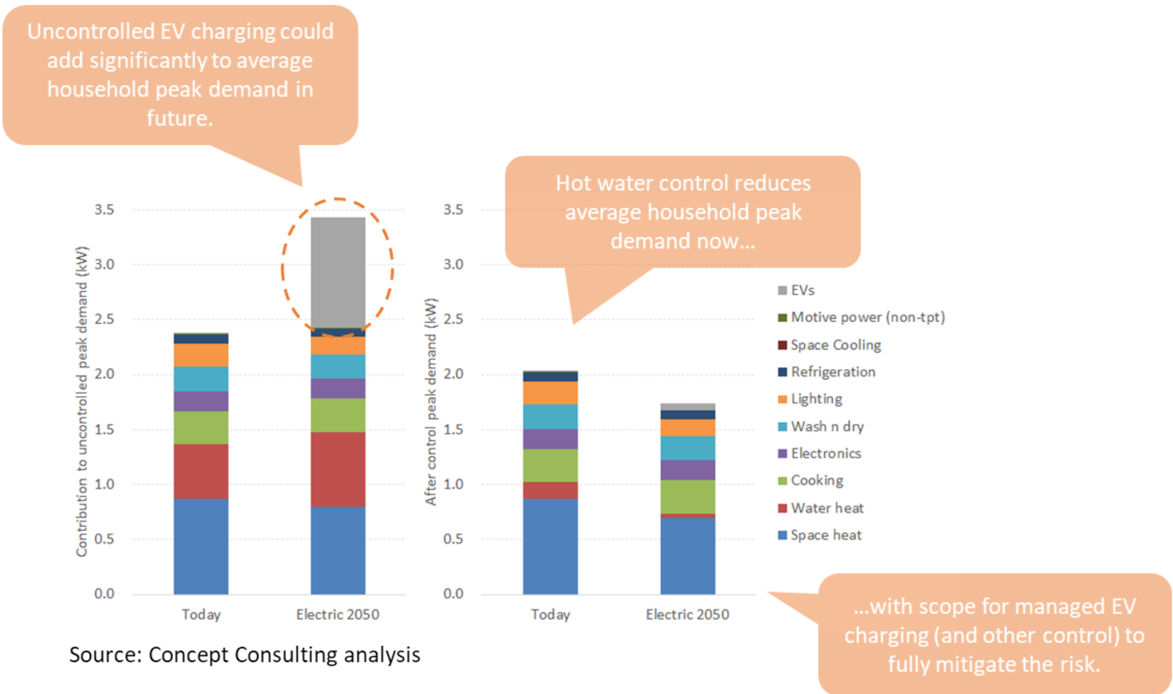
2.7. Enhance Controllability Discounts

31. Aurora Energy 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.

32. Managed load discounts are effectively already applied to ripple-controlled water heating. As Aurora Energy transition to new structures and rebalance pricing levels, there will be a need to ensure the discount for controllability is consistent with LRMC signalling, and to explore how discounts can be applied for managed EV charging (and potentially other technologies).

33. 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

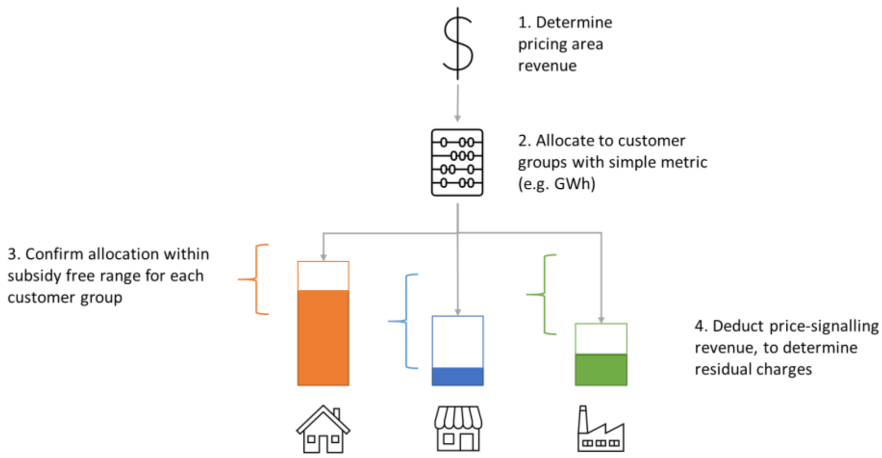


Source: Concept Consulting analysis

2.8. Simplify Cost Allocation Within Pricing Areas

34. Much of the complexity in the 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 the proposed cost allocation within pricing areas.

Figure 6: Cost allocation within pricing areas



35. To support simpler allocation, we have developed a subsidy-free range methodology. The methodology provides 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, and demand prices) and potentially simplify the non-residential load groups (e.g., with fewer bands).

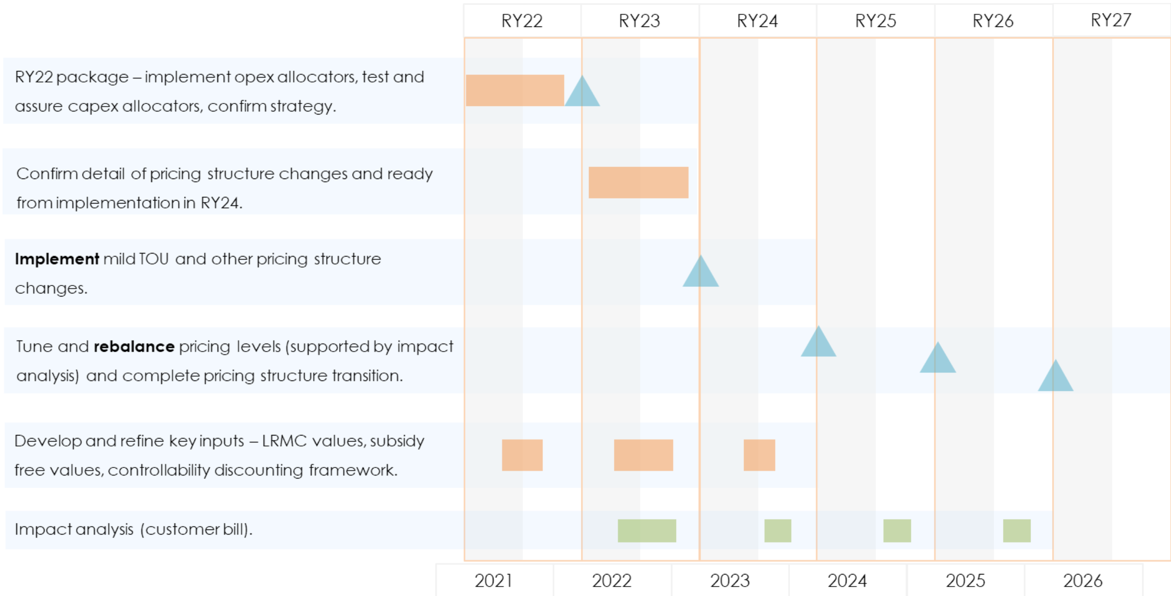
2.9. Implement Gradually and Carefully

36. With the CPP programme of catch-up investment and capability build underway, and current inflation pressures our charges will already reflect relatively large year-on-year changes in pricing. While implementing pricing change is important, Aurora Energy 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 peak 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 customers.
37. Aurora Energy consulted on its strategy in RY22 and are now executing the plan to fully implement pricing improvements by RY27.
38. The work plan for the past year has been focussed on developing LRMC estimates to inform the implementation of mild ToU tariffs from 1 April 2024. We will continue to refine and

tune the strength of ToU pricing signals over the next three years so that ToU prices are fully cost-reflective from RY27.

39. Aurora Energy 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 the timeline for implementing residential pricing changes.

Figure 7: Summary distribution pricing roadmap



40. The focus for the next year will be on simplifying the pricing structure for non-residential customers to ensure that the appropriate pricing signals are in place to encourage efficient network use.

2.10. Customer Impact

41. As Aurora Energy implements its strategy, it will alter the 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. During consultation with customers in 2021, Aurora Energy introduced four customer personas to provide an indication of how price changes could affect different consumer types. Figure 8 is an extract from our consultation materials.

Figure 8: Customer impacts of pricing strategy

PROFILE:
A large family living in Dunedin.

CONSUMPTION SUMMARY:
Annual usage of 15,000 kWh. 75% of their electricity usage is during peak times. They have opted for the most common, all-inclusive price option.

CONSUMPTION PATTERN: Typical usage pattern, with two daily peaks.

IMPACT ON NETWORK: Usage coincides with the network peaks that drive the level of network infrastructure required.

IMPACT OF PRICING CHANGES: Overall, this family should expect a slight reduction in their charges. They will see a decrease in their consumption-based charges, partially offset by an increase in their fixed charges.

OPPORTUNITY TO REDUCE FUTURE DISTRIBUTION CHARGES: The introduction of ToU prices may provide an opportunity for this family to save money by shifting a portion of their usage to off-peak times if they are able to.

PROFILE:
A retired couple living in Clyde, at home during the day.

CONSUMPTION SUMMARY:
Annual usage of 9,000 kWh. Approximately 30% of their electricity usage is for hot-water which is subject to control and billed at a lower rate.

CONSUMPTION PATTERN: This couple uses electricity throughout the day, with half of their usage outside of peak times.

IMPACT ON NETWORK: Because this couple has opted to let their hot-water be controlled, in exchange for a reduced price, Aurora Energy has more ability to manage network peaks.

IMPACT OF PRICING CHANGES: Overall, this couple should expect to pay about the same. They will pay more for daily fixed charges, which will be offset by lower consumption charges.

OPPORTUNITY TO REDUCE FUTURE DISTRIBUTION CHARGES: The introduction of ToU prices may provide an incentive for this couple to save money by further shifting their usage to off-peak times if they are able to.

PROFILE:
A working couple living in Queenstown. They use electricity for their heating and appliances only. They use gas for their cooking and hot-water needs.

CONSUMPTION SUMMARY:
Annual usage of 5,000 kWh. They are charged an uncontrolled price.

CONSUMPTION PATTERN: This couple consumes 75% of their electricity during the evening and morning peak times.

IMPACT ON NETWORK: This couple's usage mostly coincides with our network peaks which drive the level of network infrastructure required. While this couple opt to use gas as an alternative for some of their energy needs, this does not reduce the mostly fixed costs of distributing electricity to their house.

IMPACT OF PRICING CHANGES: Overall, this couple should expect an increase in their charges due to an increase in fixed charges.

OPPORTUNITY TO REDUCE FUTURE DISTRIBUTION CHARGES: The introduction of ToU prices may provide an incentive for this couple to save money by shifting their usage to off-peak times if they are able to.

PROFILE:
A working couple in Wanaka who have an Electric Vehicle (EV).

CONSUMPTION SUMMARY:
Annual usage from the grid of 10,500 kWh, including 2,500 kWh for their EV. They are charged an uncontrolled price.

CONSUMPTION PATTERN: This couple consumes 75% of their household electricity during peak times, and 100% of their EV charging during off-peak network times.

IMPACT ON NETWORK: Most of this couple's household consumption coincides with our network peaks.

IMPACT OF PRICING CHANGES: Overall, this couple should expect a decrease in their consumption-based charges, off-set by an increase in fixed charges. Given they already charge their EV at off-peak times, they will also be rewarded by lower off-peak ToU prices.

OPPORTUNITY TO REDUCE FUTURE DISTRIBUTION CHARGES: By continuing to charge their EV at off-peak times, they will benefit from lower ToU prices.

43. As progress is made through the gradual implementation of the pricing strategy, Aurora Energy will continue to monitor the impact of changes to understand the impact on customer affordability. Section 7 of this document outlines the impacts of this year's pricing changes.

2.11. Alignment to Electricity Authority Reform objectives

44. In September 2022, the Electricity Authority published an open letter to distributors outlining their expectations for pricing reform. Table 1 summarises the five areas of focus from the open letter alongside an explanation of how Aurora Energy's strategy is meeting the Electricity Authority's expectations.

Table 1: Electricity Authority's reform objectives

Focus Area	How Aurora Energy is meeting reform expectations
Distributors' roadmaps responding to future network congestion	Figure 4, in section 2.3 outlines how Aurora Energy is using pricing alongside flexibility services to help operate an efficient network and respond to areas of constraint. As the uptake of EVs increases, new tariffs will be considered such as managed household service tariffs to complement existing control tariffs. Section 4 explains Aurora Energy's approach to calculating LRMC values that reflect the relative levels of congestion in each pricing area. The LRMC values are being used to inform peak ToU price signals. From 1 April 2024 we are applying mild ToU prices, with the transition to fully cost-reflective ToU prices expected to be completed by RY27.
Distributors' response to any significant first mover disadvantage (FMD) issues facing customers seeking to connect to their networks (new and expanded connections)	Aurora Energy's Capital Contributions Policy describes the approach to funding new network connections. Aurora Energy's Capital Contributions Policy applies to assets that are for the sole benefit of the new connection, or a series of new connections (e.g., a subdivision). Assets that could support future network growth are 100% funded by Aurora Energy. This approach mitigates the risk of new connections being subject to a FMD.
The extent to which distributors are following the Electricity Authority's guidance on pass-through of new transmission charges	Aurora Energy have followed the Electricity Authority's guidance to recover transmission costs through fixed charges where possible. This means that for RY25 residential transmission charges have been recovered through daily fixed charges to the extent permissible under the LFC regulations, with the balance recovered evenly from each variable charge to minimise the distortionary impact of TPM changes. For general customers the transmission charges for RY25 will be recovered through the passthrough component of the fixed daily capacity charge. Note there are other non-transmission revenue items such as IRIS penalties which are being recovered through CPD charges. We are transitioning towards recovering all passthrough from fixed daily capacity charges at a pace that will not create significant price shocks for customers.
Whether distributors are increasing their use of fixed charges to match the phase-out path of the low fixed charge tariff regulations	In line with regulation changes, Aurora Energy has continued to phase out LFC charges to support the move towards more cost-reflective pricing. RY25 is the third year of a five-year phase out that will be completed in RY27 and results in fixed charges for residential consumers increasing, from $0.45 per day to $0.60 per day from 1 April 2024.

Focus Area	How Aurora Energy is meeting reform expectations
Distributors avoiding, or transitioning away from, recovery of costs that are fixed in nature through use-based charges, such as charges based on a customer's Anytime Maximum Demand (AMD)	Prices for general customers are comprised of fixed charges (daily fixed price, capacity price, and distance price) and a Control Period Demand (CPD) price which signals consumption during congested periods. Aurora Energy do not use AMD as a basis for charging. Prices for residential customers are transitioning to fixed daily charges to the extent permissible under the LFC regulations.

3. RY25 PRICING

3.1. PRICING CHANGES MADE THIS YEAR

45. Following publication of the refreshed pricing strategy and roadmap on 1 April 2021, Aurora Energy has made significant progress towards implementing more cost-reflective pricing. This section summarises the key changes that will affect prices for the RY25 year:

45.1. **Phase out of Low-User Fixed Charges (LFC)** – In line with regulation changes, Aurora Energy has continued to phase out LFC charges to support the move towards more cost-reflective pricing. RY25 is the third year of a five-year phase out that will be completed in RY27 and results in fixed charges for residential consumers increasing, from $0.45 per day to $0.60 per day from 1 April 2024.

45.2. **ToU price differentials introduced** – As signalled in last year's Pricing Methodology, for residential customers we will be implementing a mild price differential between peak and off-peak consumption from 1 April 2024. We will transition to more cost-reflective tariffs over the next three-years, so by 2027 tariffs will more closely reflect the estimated Long-Run Marginal Cost (LRMC) of each pricing area. Section 4 of this document outlines our approach to calculating LRMC.

3.2. CUSTOMER CONSULTATION

46. In November 2021 and December 2021 Aurora Energy consulted with customers to get their views on:
    - The proposed strategy to improve the cost-reflectiveness of future prices;
    - the allocation of capital investment-related costs to each of the pricing areas; and
    - the clarity of the Pricing Methodology document.

47. The consultation process was comprehensive, utilising multiple advertising channels to reach customers, and including workshops with consumers in Dunedin, Central Otago/Wānaka and Queenstown.

48. Sixty-six (66) individual submissions were received and one submission from an electricity retailer. The submissions received were analysed and identified the following key themes:
    - Most found the pricing strategy clear.
    - ToU pricing had mixed support in different regions.
    - Residential customers understood the reasons for increased proportion of fixed charges but had concerns about low-occupancy households and devaluation of solar and electric vehicle investments.

- Limited support for the proposed cost allocation method using RAB, with uncertainty about better cost-reflective alternatives.
- Suggestion for simpler and consumer friendly language in the pricing methodology.

49. The detailed response to submissions is available on Aurora Energy's website.

50. The consultation activities we conducted in 2021 followed extensive customer engagement undertaken as part of our CPP proposal in June 2020. During this period, customers indicated 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.

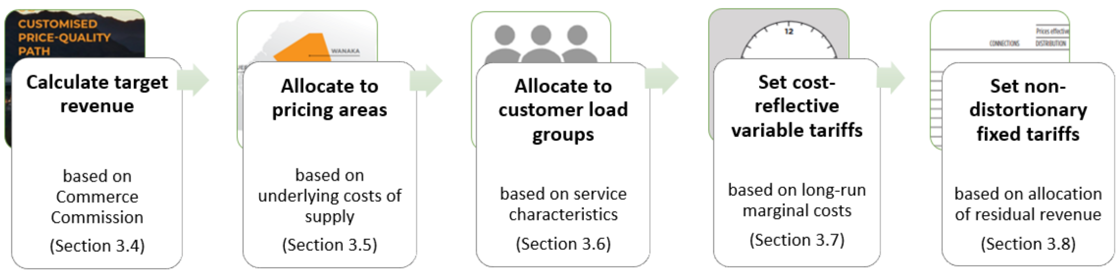
51. No additional pricing related consultation activities have been conducted in RY23 and RY24 as the focus has been on implementing the significant changes outlined within the CPP delivery plan. Further consultation is proposed to be conducted in RY25/26 specifically targeted at non-residential customers.

3.3. Pricing Approach

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

53. Figure 9 summarises the five steps Aurora Energy followed to set customer prices for RY25, with more detail provided in sections 3.4 to 3.8.

Figure 9: Pricing process



3.4. Calculate Target Revenue

54. 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.

55. In March 2021, the Commission published its final decision on the CPP application[2], including a schedule of forecast net allowable revenue for the five years from 1 April 2021 to 31 March 2026.

56. This means the RY25 forecast allowable revenue will be $158,101,807, an increase of $17.1m (12.1%) when compared to the previous year, and results in an average price increase of 7.4% once growth in chargeable volumes has been included. The components of total forecast allowable revenue are listed in Table 2, along with a comparison to the previous year's values.

Table 2: Components of forecast allowable revenue ($m)

Component	RY25	RY24
Capital related costs		
Asset revaluations and other regulatory revenue	(15.0)	(13.6)
Depreciation	23.1	21.5
Return on capital	30.1	32.3
Tax	6.8	6.2
Operational costs		
Business support	15.3	15.7
Routine and corrective maintenance and inspection	9.6	10.4
Service interruptions and emergencies	4.9	4.8
System operations and network support	15.1	15.4
Vegetation management	3.9	3.9
Passthrough and recoverable costs		
Capex Incentive Amount	(1.6)	(1.5)
Capex Wash-up Adjustment	(0.8)	(0.8)
Commerce Act levies	0.5	0.3
Electricity Authority levies	0.3	0.3
Fire and Emergency Management New Zealand (FENZ) levies	0.0	0.0
Local Authority rates	1.6	1.2
Opex Incentive Amount	28.4	20.9
Quality Incentive Adjustments	(0.6)	(0.6)
Transmission Costs	26.2	24.9
Utilities Disputes levies	0.1	0.1

2 Commerce Commission. (2021). Aurora Energy Limited Electricity Distribution Customised Price-Quality Path Determination 2021. Available form Commerce commission website: https://comcom.govt.nz/regulated-industries/electricity-lines/projects/our-assessment-of-aurora-energys-investment-plan

Component	RY25	RY24
Opening Wash-up Account Balance	25.5	14.6
Target Revenue (before revenue limit and wash-ups applied)	173.3	156.0
Revenue deferred to future periods	(15.2)	(14.9)
Target Revenue	**158.1**	**141.0**

3.4.1. Revenue deferred to future periods

57. The Commission's determination places a limit on the annual increase in revenue that can be recovered from prices. For the year commencing 1 April 2024, Aurora Energy's target revenue is higher than the allowable revenue limit calculated in accordance with the Commission's determination. This means that there is a surplus in revenue that cannot be recovered from prices this year, and instead will be recovered from consumers in future regulatory periods, along with revenue deferred from prior years.

3.5. Allocate to Pricing Areas

58. The second step in Aurora Energy's pricing process is to allocate the forecast allowable revenue to the three pricing areas:
    - Dunedin
    - Central Otago and Wānaka
    - Queenstown
59. Proxy allocators have been chosen for each component of forecast allowable revenue, to align the revenue collected from each pricing area with the underlying costs of supplying services. Table 3 details the allocation basis and rationale for allocating each component of target revenue to a pricing area.

Table 3: Pricing area allocators

Component	Allocator	Rationale
Capital related costs:		
– Return on capital – Depreciation – Tax – Asset revaluations and other regulatory revenue	Regulatory Asset Base	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.
Operational costs:		

Component	Allocator	Rationale
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 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	Directly allocated by Transpower	These expenses are directly allocated to GXPs based on Transpower's Transmission Pricing Methodology.
Local authority rates	Regulatory Asset Base	Rates are levied by councils based on RAB value, so we have allocated costs to each pricing area on this basis.
Commerce Act levies	Regulatory Asset Base	Commerce Act levies are allocated to distributors based on RAB value, so we have allocated costs to each pricing area on this basis.
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	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	Regulatory Asset Base	FENZ levies are broadly based on asset values, via insurance premia. We have allocated FENZ levies to pricing areas based on the RAB value of each pricing area.

Component	Allocator	Rationale
Quality incentive adjustment	ICP count	The quality incentive in RY25 is a penalty for not meeting regulated quality targets. The incentive (refund) is socialised across the network to recognise scale benefits. We have used ICP count to do this.
IRIS – Capex	Regulatory Asset Base	The capex IRIS incentive in RY25 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 RAB value of each pricing area.
IRIS – Opex	Previous year's distribution charges	The opex IRIS incentive in RY25 is a positive adjustment that relates to 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 the capital related costs and operational costs listed in Table 2. This approach recognises that the revenue deferred cannot be allocated to a specific cost item.

60. Each component of forecast allowable revenue is allocated to pricing areas based on the allocator in Table 3 and the allocation percentages specified in Table 4.

Table 4: Pricing area allocation percentages

	Pricing Area		
Cost Allocators	Dunedin	Central	Queenstown
ICP Count	60.4%	24.1%	15.5%
Total Circuit Length	38.2%	45.5%	16.2%
Overhead Circuit Length	43.9%	45.7%	10.4%
Prior year distribution revenue	50.4%	31.8%	17.8%
Transmission Costs	55.9%	20.4%	23.7%
MWh	57.8%	23.0%	19.1%
Regulated Asset Base	47.4%	34.1%	18.5%
Regulated Asset Base (Depreciation)	48.5%	32.7%	18.8%

61. The resulting forecast allowable revenue to be recovered from each pricing area is detailed in Table 5.

Table 5: Total forecast allowable revenue by pricing area

Components ($m)	Dunedin	Central	Queenstown	Total
Capital related cost	23.9	16.7	9.3	**49.9**
Operational costs	29.0	16.8	8.3	**54.0**
Passthrough and recoverable costs	28.7	14.2	11.2	**54.1**
Total forecast allowable revenue	**81.6**	**47.7**	**28.8**	**158.1**
% of forecast allowable revenue	51.6%	30.2%	18.2%	**100.0%**

3.6. Allocate to Customer Load Groups

62. After determining the forecast allowable revenue for each pricing area, the forecast allowable revenue to customer load groups is determined. The categorisation of load groups is based on physically distinguishable characteristics and recognises that customers use the network differently. Large customers make proportionately greater use of high voltage (HV) network elements than smaller customers. This is taken into account in the pricing methodology by establishing load groups and allocating forecast allowable revenue to these load groups proportional to their use of the network. This approach means that prices will differ between pricing areas, and between load groups. The load groups are shown in Table 6.

Table 6: 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 0A	Unmetered builders temporary supply with maximum capacity of 15 kVA.
Load Group 1 & 1A (including residential)	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.

63. Forecast allowable revenue for each pricing area is allocated to customer load groups by choosing proxy allocators for each revenue component. Table 7 details the allocation basis and rationale for allocating each component of target revenue to a customer load group.

Table 7: Customer load group allocators

Component	Allocator	Rationale
Capital related costs:		
– Return on capital – Depreciation – Tax – Asset revaluations and other regulatory revenue	Regulatory Asset Base	All capital related costs are allocated to load groups based on each load group's use of the LV and HV network. RAB value is used to determine the relative proportion of network assets.
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	Control Period Demand (CPD)	Within each pricing area, maintenance costs are allocated to each load group based on its contribution to CPD.
Vegetation management	CPD	Within each pricing area, vegetation costs are allocated to each load group based on its contribution to CPD.
Service interruptions and emergencies	– 50% allocated by ICP count – 50% allocated by CPD	Faults may occur at individual ICPs or at distribution equipment affecting wide areas. ICP count explains individual fault contributions in each load group while CPD reflects each load group's contribution to the maximum system demand.
Passthrough and recoverable costs:		
Transmission costs	MWh	Transmission costs have been allocated to customer load groups using MWh, which approximates the method of cost allocation used by Transpower.
Local authority rates	Regulatory Asset Base	Rates are levied by councils based on asset value, so we have used RAB as the basis of the allocation to load groups.

Component	Allocator	Rationale
Commerce Act levies	Regulatory Asset Base	Commerce Act levies are allocated to distributors based on RAB value, so this is used as the basis of the allocation to load groups.
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	Regulatory Asset Base	FENZ levies are broadly based on asset values, via insurance premia. We have allocated FENZ levies based on the RAB value used by each load group.
Quality incentive adjustment	ICP count	The RY25 quality incentive is a penalty for not meeting regulated quality targets. The incentive (refund) is socialised across load groups to recognise scale benefits. ICP count has been used to do this.
IRIS – Capex	Regulatory Asset Base	The RY25 capex IRIS incentive is a penalty for overspending capital expenditure allowances in the previous regulatory period. The capex IRIS incentive (refund) amount has been allocated based on the estimated RAB value of each load group's use of network assets.
IRIS – Opex	Previous year's distribution charges	The RY25 opex IRIS relates to operational expenditure allowances in the previous regulatory period. The opex IRIS incentive (refund) has been allocated 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 the capital related costs and operational costs listed in Table 8. This approach recognises that the revenue deferred cannot be allocated to a specific cost item.

64. The allocation percentages used to allocate forecast allowable revenue to customer load groups are shown in Table 8.

Table 8: Load group allocation percentages

Cost Allocators	Load Group SL	L1	L2	L3	L4	L5
Dunedin						
ICP Count	0.0%	93.9%	5.6%	0.4%	0.1%	0.0%
CPD	0.7%	65.2%	14.2%	8.2%	8.3%	3.5%
Prior year distribution revenue	0.9%	67.7%	15.8%	8.0%	6.0%	1.6%
MWh	0.5%	53.8%	16.7%	10.4%	12.9%	5.7%
Regulated Asset Base	0.5%	49.9%	10.8%	15.9%	16.2%	6.7%
Regulated Asset Base (Depreciation)	0.6%	55.3%	12.0%	13.2%	13.4%	5.6%
Central Otago & Wanaka						
ICP Count	0.0%	89.8%	9.3%	0.6%	0.2%	0.0%
CPD	0.4%	67.3%	17.0%	6.7%	8.4%	0.1%
Prior year distribution revenue	0.3%	64.3%	17.1%	8.7%	9.1%	0.5%
MWh	0.3%	45.6%	25.5%	12.7%	13.2%	2.7%
Regulated Asset Base	0.3%	39.7%	10.0%	22.1%	27.6%	0.4%
Regulated Asset Base (Depreciation)	0.3%	44.7%	11.3%	19.3%	24.1%	0.4%
Queenstown						
ICP Count	0.0%	86.5%	12.8%	0.5%	0.2%	0.0%
CPD	0.4%	61.2%	20.4%	6.7%	10.5%	0.8%
Prior year distribution revenue	0.3%	60.9%	21.2%	10.6%	6.6%	0.3%
MWh	0.3%	43.7%	25.3%	9.0%	18.4%	3.3%
Regulated Asset Base	0.2%	40.3%	13.5%	17.2%	26.8%	1.9%
Regulated Asset Base (Depreciation)	0.3%	45.2%	15.1%	14.7%	23.0%	1.7%

65. The allocators chosen in Table 7 are proxies 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.

66. When applying the load group allocations described in Table 7 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 RY24 and RY25.

67. Accordingly, we have applied judgement to moderate revenue changes between load groups within the same pricing area. Table 9 shows the revenue allocation by load group, before and after the application of judgement. For RY25 we have chosen to set prices at a level which will recover $0.1m less revenue than the forecast allowable revenue.

Table 9: Forecast allowable revenue by customer load group ($m)

Customer Load Group	RY25 forecast allowable revenue before judgement applied	Judgement applied	RY25 forecast revenue after judgement applied
Dunedin			
Street Lighting	0.4	0.2	0.6
Load Group 0 & 0A	0	0.1	0.1
Load Group 1 & 1A	55.0	-0.6	54.4
Load Group 2	9.6	2.3	11.9
Load Group 3 & 3A	6.8	-0.3	6.5
Load Group 4	6.9	-0.8	6.1
Load Group 5	2.8	-1.0	1.8
Total Dunedin	**81.4**		**81.4**
Central			
Street Lighting	0.1	0.0	0.1
Load Group 0 & 0A	0	0.5	0.5
Load Group 1 & 1A	28.1	2.3	30.4
Load Group 2	6.8	1.0	7.8
Load Group 3 & 3A	5.4	-1.7	3.7
Load Group 4	6.4	-1.9	4.5
Load Group 5	0.3	-0.1	0.2
Total Central	**47.2**		**47.1**
Queenstown			
Street Lighting	0.1	0.0	0.1
Load Group 0 & 0A	0.0	0.2	0.2
Load Group 1 & 1A	16.2	0.6	16.8
Load Group 2	5.2	0.9	6.1
Load Group 3 & 3A	2.8	-0.3	2.5
Load Group 4	4.1	-1.3	2.8
Load Group 5	0.4	-0.1	0.3
Total Queenstown	**28.8**		**28.7**
Distributed generation	0.7		0.7
TOTAL NETWORK	**158.1**		**158.0**

3.7. Set Cost-Reflective Variable Tariffs

68. Cost-Reflective tariffs send an important signal about the relative cost of peak demand on the network, and they encourage customers to shift their electricity usage to lower priced, off-peak periods where feasible.

69. In line with the pricing strategy and the phase-out of LFC regulations Aurora Energy will refine the strength of the variable tariffs over the next two-years so that by RY27 these tariffs will fully signal the economic cost of consumption during peak periods. The amount of revenue collected through variable residential tariffs has been increased to offset the LFC limits imposed on fixed tariffs.

3.8. Set Non-Distortionary Fixed Tariffs

3.8.1. Residential Tariffs

70. The residual revenue for each pricing area is determined by deducting the amount of revenue to be collected from variable tariffs in accordance with section 3.7, from the amount of revenue allocated to residential tariff types in section 3.6. The residual amount of revenue is then allocated to fixed daily charges in a 'non-distortionary' manner. In other words, the fixed charges are designed to not influence customer consumption choices.

71. The price structure for Residential connections is not the preferred recovery mechanism but has been partially mandated by the LFC Regulations. The 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 60 cents per day for the year commencing 1 April 2024.

72. 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 is 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.

3.8.2. General Tariffs

73. Within load groups in each pricing area, a pricing structure has been adopted that is intended to reflect the impact of customers' consumption (and other) decisions on the key drivers of costs. In general terms, costs are driven by a combination of customer numbers, electricity conveyance volumes, and (peak) capacity. However, to 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.

74. 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.

75. 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).

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

77. 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).

Table 10 describes the allocation of forecast allowable revenue to price components. Further detail about each price component is provided in sections 3.8.3 to 3.8.5.

Table 10: Forecast revenue by price component ($m)

	Price Component	Dunedin	Central Otago and Wānaka	Queenstown	Total	% of Total
Distribution ($000’ s)	Fixed	0.6	0.5	0.4	1.5	0.9%
	Volumetric	34.0	19.9	9.7	63.7	40.3%
	Capacity kVA	3.8	4.3	2.7	10.8	6.8%
	KVA-KM	0.4	1.0	0.2	1.6	1.0%
	CPD kW	12.9	6.9	4.2	24.1	15.2%
	Equipment	0.5	0.2	0.2	0.9	0.6%
	Street lighting	0.4	0.1	0.1	0.6	0.4%
	Generation	0.2	0.6	0.0	0.7	0.5%
	Subtotal	**52.8**	**33.5**	**17.5**	**103.8**	**65.7%**
Pass-	Fixed	10.9	4.5	2.8	18.2	11.5%
	Volumetric	6.4	4.5	3.3	14.2	9.0%

	Capacity kVA	9.7	4.6	4.3	18.5	11.7%
	CPD kW	1.5	0.7	0.8	3.0	1.9%
	Street lighting	0.2	0.0	0.0	0.3	0.2%
	Subtotal	**28.7**	**14.2**	**11.2**	**54.1**	**34.3%**
Total		**81.5**	**47.7**	**28.7**	**158.0**	**100.0%**

3.8.3. Residential Distribution Cost Recovery Components

78. Two components of delivery prices are used, and the pricing details are outlined in Appendix A - Schedules A to D. The components are as follows:

Volumetric Price

79. Volumetric prices are defined by legacy 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 Otago / Wanaka and Queenstown 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 because historically, 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.

3.8.4. 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 D. The price components are as follows:

Fixed Price

- 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 based on installed distribution transformer capacity, is the lesser of the installed distribution transformer capacity (kVA) and the 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

89. 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.

90. 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

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

92. 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.

93. 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, and to last typically for two to three hours (but could last for up to ten hours on occasions). It 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.

94. 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. 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.

95. For the year commencing 1 April 2024 we will be trialling a CPD credit scheme for consumers in the Upper Clutha and Wanaka areas who are able to provide network support during CPD periods. The scheme will operate by including 50% of the kwh exported during CPD periods in the calculation of average CPD kW for the year. We encourage customers who meet the criteria below to contact Aurora Energy, using the email address: sales@auroraenergy.nz

- Installation is in the Upper Clutha / Wanaka area.

– Installation is at least 69 kVA of connected capacity.
– Installation is half-hourly metered.
– Installation is capable of exporting during CPD periods.

Eligibility for the scheme is at the sole discretion of Aurora Energy and is available on a trial basis for the year commencing 1 April 2024.

Equipment Price

96. 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

97. Aurora Energy may 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.

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

3.8.5. Pass-through Cost Recovery Prices

Residential Connections

99. The fixed price has been set at 60 cents per day, which is the maximum fixed price permitted under the LFC Regulations for the year commencing 1 April 2024.

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

General Connections

101. 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, allocated pass-through costs are recovered by way of an assessed capacity price ($ per installed kVA) or CPD price.

4. Long-Run Marginal Cost & Subsidy-Free Range

4.1.1. Long-Run Marginal Cost Overview

102. Our avoidable costs are driven by the need to provide capacity (i.e., having enough headroom to reliably cover peak demand). Our other costs, such as renewal capex and operations are largely fixed and do not vary significantly when consumption increases.

103. For tariff design, it makes sense to focus on signalling the cost of providing capacity to meet peak demand. Long-Run Marginal Cost (LRMC) is the economic term for the cost (including any new capex and opex) of supplying extra demand. LRMC is near zero during off-peak periods, so we focus on demand at peak times that would influence our plans for adding new capacity.

4.1.2. Long-Run Marginal Cost Approach

104. After researching alternative methods of calculating LRMC, we have chosen to adopt the most common method, Average Incremental Cost (AIC). AIC is the present value of the stream of (least cost) capital expenditure needed to satisfy the projected demand divided by the present value of the stream of demand itself.

105. For an individual unit, the Incremental Cost (IC) is divided by the number of units in the increment to get the AIC. The basic methodology for estimating the AIC is:

    1. forecast the relevant expected demand characteristics into the foreseeable future,

    2. estimate the system requirements and augmentations that would be required over time to meet expected demand levels,

    3. estimate the likely cost of these requirements, and

    4. calculate the Marginal Capacity Cost (MCC) as the average cost per unit of anticipated demand of the total increment to capacity required for the forecast period.

106. Under the AIC approach the LRMC formula is:

    AIC LRMC = (NPV (Capex)+NPV(Opex))/(NPV(Demand))

107. The AIC approach gives marginal cost estimates, which smooth out lumpy expenditure over time while at the same time reflecting the general level and trend of future costs, which will be incurred as demand increases.

108. A strict application of the AIC method may result in a ‘saw-tooth’ pattern of LRMC estimates – i.e., a value that rises sharply each year before collapsing once an investment is made. To help smooth the ‘saw-tooth’ pattern we apply a de-rating of future investments to consider:

   1. shiftability – there is no point sending a signal for projects where a change in consumer consumption could not actually lead to a change in the timing or sizing of an investment. Most projects become locked into our workplan on an annual cycle, so we can completely discount year one projects. Larger projects (including most grid projects) start to become locked in several years in advance as land access is committed, design work is completed, equipment is ordered, and contracts are let. To reflect this, we use a shiftability curve that starts at zero for year one and increases to 100% by year five.

   2. consumer behaviour – cost reflective tariffs predominantly work by influencing end user investment choices (for matters such as appliance energy efficiency and choice of electricity vs. other fuels) and their enduring usage habits (such as electric vehicle charging routine). This supports our logic for de-rating near-term investments and introduces a reason to de-rate long-term investments:

      a. near term – only a fraction of end users will make major appliance decisions each year, so there is a natural lag between a change in price signal and any meaningful impact on usage.

      b. long-term – the appliance choices end users make today may have a limited effect on peak demand in the future where the lifecycle of today’s appliances has expired, and they have been replaced.

4.1.3. Long-Run Marginal Cost Calculations for RY25

109. We have calculated LRMC values for each pricing area using growth projects identified in the draft RY25 Asset Management Plan (AMP). The resulting LRMC values reflect the relative levels of congestion in each network.

110. This is the first year we have performed a detailed LRMC calculation, and we have decided to not rely on the LRMC values to solely inform the ToU peak tariffs to apply from 1 April 2024. We have applied a degree of judgement to the calculated ToU peak tariffs to mitigate the risks of unintended bill shocks. This is consistent with our pricing strategy approach to implement cost-reflective pricing in a careful and gradual manner. We intend to have completed our transition to fully cost-reflective ToU prices by 1 April 2026, which aligns to the phase out of the LFC legislation.

111. Table 11 outlines the LRMC calculations and resulting ToU peak price signals. The Central Otago & Wanaka pricing area has the highest LRMC value, reflecting upcoming investments such as a new 66 kV line into the Upper Clutha area. The Queenstown pricing area has the next highest LRMC value, reflecting the forecast investment in new substations to support

population growth. Dunedin has the lowest LRMC value, which reflects a more stable population base and some expected growth from electrification.

Table 11: RY25 LRMC calculations and ToU peak price signals

Pricing area	LRMC ($/kW)	Calculated ToU Peak Signal (cents/kWh)	ToU Peak Signal applied from 1 April 2024 (cents/kWh)
Dunedin	$107	3c	3c
Central Otago & Wanaka	$882	24c	5c
Queenstown	$455	12c	4c

4.1.4. Subsidy-free Range

112. The subsidy-free range (SFR) provides a cost allocation range where all customer groups benefit from sharing a network. When prices are subsidy-free every consumer group:

    1. is paying at least the cost it adds to the network (its avoidable cost).
    2. is paying no more than the cost of a dedicated network (its standalone cost).
    3. benefits from using a network whose common costs are shared across many consumer groups.

113. There is usually a wide range between avoidable and standalone costs, so the SFR is not useful to allocate costs, rather it just establishes boundaries that we should ensure allocation remains within. As such, we intend to use subsidy-free values as a check of our cost of supply allocations outlined in section 3.6.

114. While we are yet to complete detailed SFR calculations, based on initial analysis we are confident that our granular and transparent allocation of costs in our Cost of Supply Model (CoSM) has resulted in cost allocations that are within the SFR. In particular, asset related costs are allocated based on the asset types used by each consumer group – this should ensure that cost allocations fall within the SFR.

115. We intend to complete SFR calculations as part of the ‘simplify cost allocation within pricing areas’ step of our pricing strategy. This work is expected to be completed by RY26.

5. Customer Connection Definitions

5.1. Residential Connection Definition

116. 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.

117. In order to be eligible for Residential pricing, premises must comply with the definition of 'home' given in the LFC Regulations.

118. 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.

119. 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.

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

5.1.1. Potable Water Supplies for Residential Connections

121. 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.

122. The potable water option only applies to connections in the Queenstown and Central Otago/Wānaka pricing areas, and to qualify, the potable water connection should not be subject to inconsistent network load control (e.g., irrigation control).

5.1.2. Sheds and Out-buildings Supplied from Separate Connections

123. 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.

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

124. 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.

125. 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 following a request received from a retailer or customer.

126. 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 Aurora Energy with details of the customer's previous residence (or residences if more than one) during that period, so the customer's total annual consumption can be assessed. 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 the consumption information relating to that previous residence.

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

127. 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.

5.2. General Connection Definition

128. General connections are all connections that are not Residential connections as defined in section 5.1; however, there are several sub-sets of General connections which each have their own qualification criteria.

5.2.1. Unmetered Load

129. 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 Electricity Authority.

130. 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 – see 5.2.2 below);
- 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.

131. 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.

132. 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.

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

5.2.2. Distributed Unmetered Load

134. 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

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

136. 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 the Queenstown, and Central Otago/Wānaka pricing areas a combination of a daily fixed price (on a per lamp basis) and volumetric prices are used to charge electricity retailers for these connections.

Other Distributed Unmetered Load (Dunedin only)

137. 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.

138. 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.

139. Other DUML connections in the Queenstown, and Central Otago/Wānaka pricing areas will be charged according to the street light pricing plan.

5.2.3. Temporary Supply

140. 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.

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

142. 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.

5.2.4. Capacity Based Pricing Groups

143. 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 3.8.3 and 3.8.4 outline the applicable pricing for these connections.

6. Seasonal Loads

6.1. Background

144. 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.

145. 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.

6.2. Delivery Pricing Recovery

146. 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.

6.3. Policy

147. 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.

7. Other Pricing Considerations

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

- prices apply per ICP;
- 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.

149. 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).

150. 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.

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

7.1. Non-standard Contracts

152. 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.

153. Aurora Energy currently has one non-standard agreement, covering two separate ICPs. We expect to generate approximately 0.2% of target revenue ($0.4m) from these two ICPs for the year ending 31 March 2025. The prices are set to recover the direct costs of supply (including capital investment and transmission) as well as an apportionment of shared network costs. This ensures the pricing is consistent with the Electricity Authority's pricing principles by being subsidy free (greater than avoidable costs, and less than standalone costs).

154. The service levels for the non-standard contract is based on an n-security of supply standard, consistent with other customers in the area.

7.2. Settlement Residue Allocation Methodology (SRAM)

155. Aurora Energy allocates the settlement residue received from Transpower to all customers that are directly billed by Aurora Energy. Once Aurora Energy receives the settlement residual rebates from Transpower Aurora Energy distributes rebates in proportion to the pass-through revenue collected from each customer in each respective pricing area (Dunedin, Central Otago / Wānaka, and Queenstown).

156. For example, if for the month of June, Aurora Energy receives a rebate of $100,000 from Transpower for the Dunedin pricing area and if Aurora Energy's customer "X" paid 20% of the total pass-through charges for that area during the same month, then Aurora Energy will rebate $20,000 to that customer. The remaining rebates will also be distributed among other customers in the same manner, based on the proportion of pass-through charges paid. This practice ensures that each customer benefits from the settlement residue rebate based on their respective contribution towards pass-through revenue.

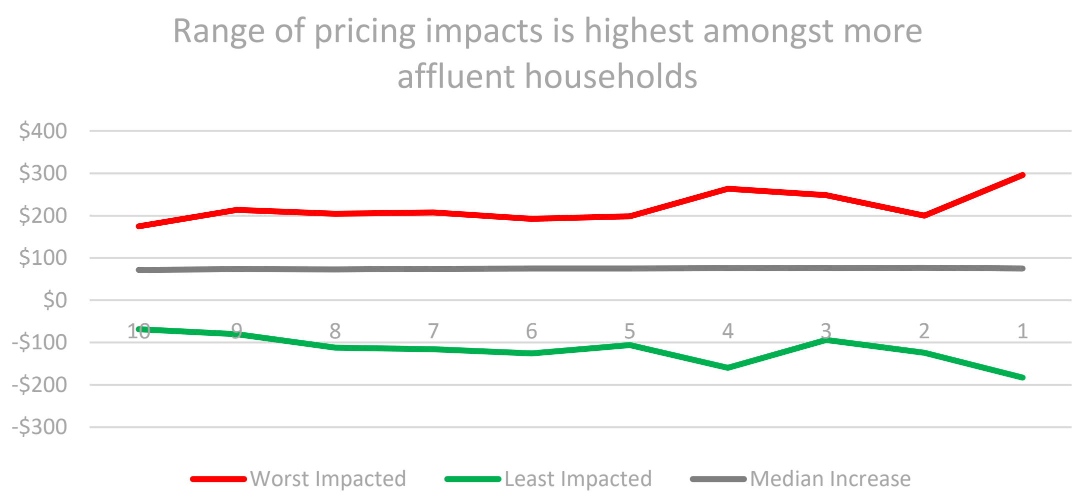
8. Affordability

157. As a supplier of essential services, Aurora Energy is mindful of the impact changes in price can have on the affordability of electricity. One of the pillars of the pricing strategy is to implement changes gradually and carefully, to avoid unnecessarily exacerbating bill pressure on customers already faced with increases due to the CPP work programme.

158. Aurora Energy has conducted an in-depth analysis of the impact of price changes on various socioeconomic groups, as classified by the New Zealand Index of Deprivation[3]. Dunedin is the only pricing region with customers in the two most deprived deciles. Consequently, our affordability analysis has primarily concentrated on this area.

159. Figures 10 to 12 present the effect of price changes on each deprivation decile in each pricing area. It is evident that the range of price impacts is smaller in decile 10 compared to more affluent deciles. The average price impact in dollar terms is similar across all decile groups.

Figure 10: Range of Dunedin price impact (p.a.) by Deprivation Index Score



[3] The New Zealand Index of Deprivation is an area-based measure of socioeconomic deprivation in New Zealand based on data collected in the previous census. The index is displayed as deciles, with decile 1 representing areas with the least deprived scores and decile 10 representing areas with the most deprived scores.

Figure 11: Range of Central Otago & Wanaka price (p.a.) impact by Deprivation Index Score

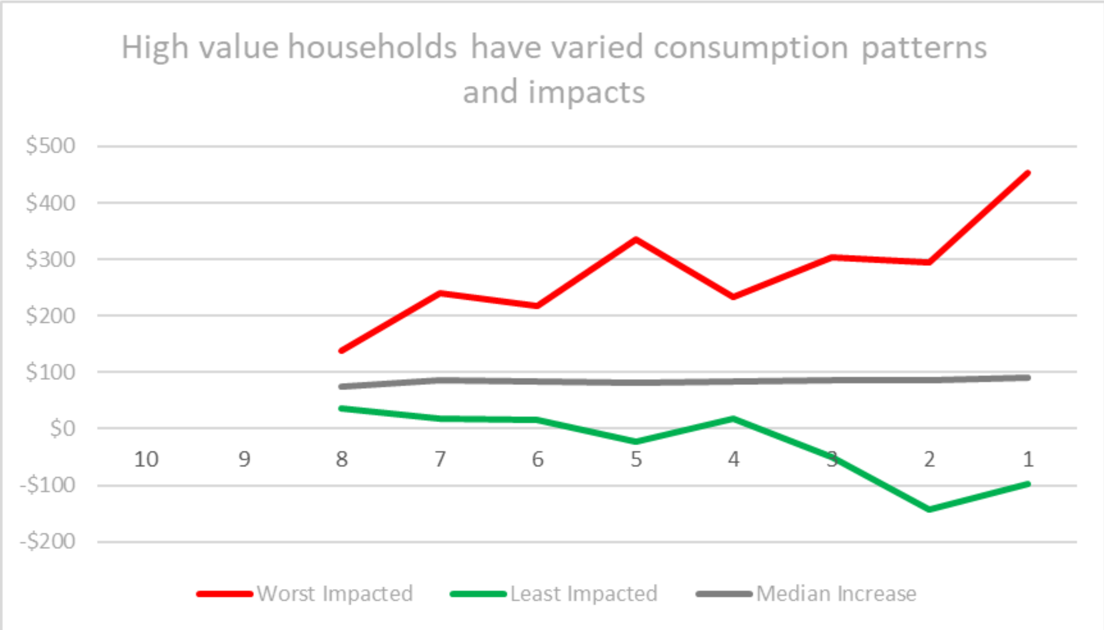
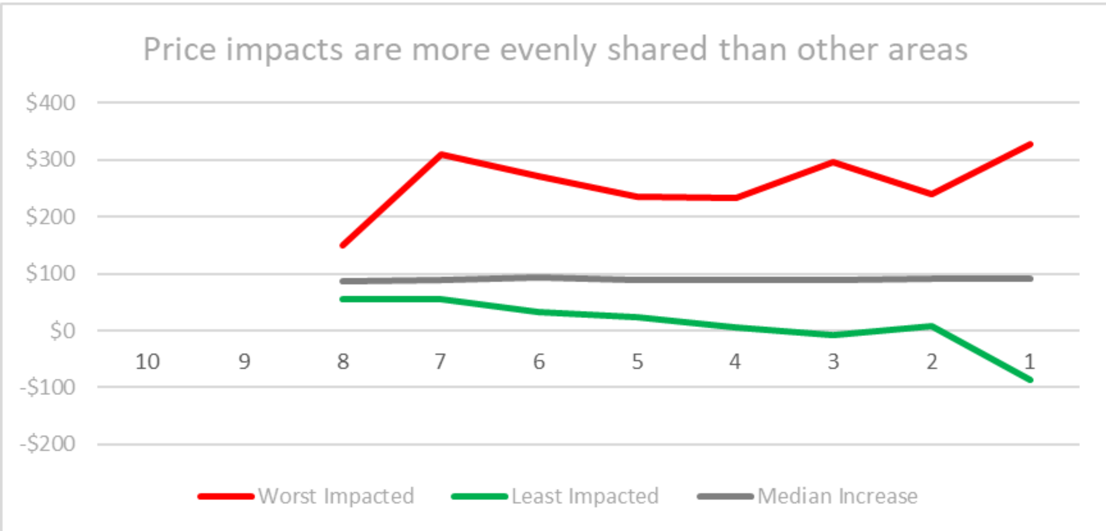
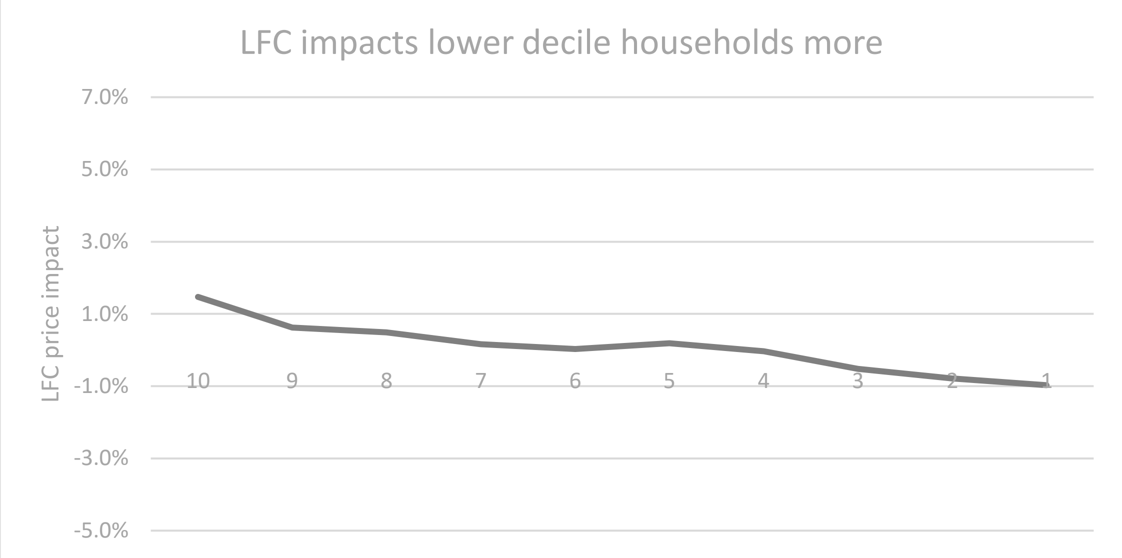


Figure 12: Range of Queenstown price (p.a.) impact by Deprivation Index Score



160. Figure 13 illustrates that the phase-out of Low Fixed Charge (LFC) regulations disproportionately affects households in the lower decile (10).

Figure 13: Dunedin LFC price impact by Deprivation Index Score



161. We encourage customers to take advantage of the independent resources available to help with energy affordability:

- Powerswitch (www.powerswitch.org.nz)
- Citizens Advice Bureau (www.cab.org.nz)
- Work and Income (www.workandincome.govt.nz)

162. Energy affordability is linked to the quality of home insulation. The following resources may be useful if customers are considering upgrading the insulation of their home. In certain circumstances, grants or subsidies are available for insulation installation:

- Energy Efficiency & Conservation Authority (www.eeca.govt.nz)
- Cosy Homes Trust (www.cosyhomes.org.nz)

9. Distributed Generation

163. This section outlines the methodology by which charges associated with the connection of Distributed Generation (DG) are calculated.

164. This methodology applies to DG connected at HV greater than 150 kW only, and generally does not apply to generation connected behind load. For generation connected behind load and connections up to 150 kW, normal delivery prices will be applied according to the installation connection capacity.

165. Small-Scale Distributed Generation (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 can avoid the full retail costs of energy (per unit), including the delivery prices.

166. 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 can avoid a significant proportion of the distribution and pass-through CPD prices.

9.1. Distributed Generation Connection Charge

167. 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 exceed that required for the local network.

168. The charge comprises three components:

– a return on investment;
– depreciation; and
– maintenance costs.

9.1.1. Return on Investment (ROI)

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

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

171. 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.

172. Where multiple DG share 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.

173. 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.

9.1.2. Depreciation

174. 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[4]. Accordingly, the calculation will be:

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

175. Where multiple DG share 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.

176. 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.

9.1.3. Maintenance

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

178. 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.

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4 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.

Example:

179. 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, 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.

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

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

9.1.4. New Generation

181. 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.

9.2. Connection Charge Adjustments

9.2.1. Inflation Adjustment

182. 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. The adjusted connection charge will take effect from 1 April.

9.2.2. Valuation Review

183. DG connection charges will be periodically adjusted for any change in the asset values that underpin the connection charge, which may have occurred because of asset renewals and replacements.

9.3. Current Prices

184. The current distributed generation prices are set out in Table 12.

185. Aurora Energy does not make payments to any owner of distributed generation.

Table 12: Distributed generation prices

Generation Details			
Generator	GXP	Installed Capacity (MW)	Connection
Generator 1	HWB	75	$ 156,625
Generator 2	CYD	29.8	$457,974
Generator 2	CML	4.3	$65,625
Generator 2	FKN	2.1	$32,635
Generator 3	CYD	2.2	$32,989

10. Glossary

Abbreviation	Definition
ACOT	Avoided Cost of Transmission
ADRs	Additional Disclosure Requirements
AMD	Anytime Maximum Demand
ATR	Avoided Transmission Rate
Capex	Capital Expenditure
CMD	Co-incident Maximum Demand
CML	Cromwell
CMP	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	the Electricity Industry Participation Code
CoSM	Cost of Supply Model
CPD	Control Period Demand
CPI	the Consumers' Price Index published by Statistics New Zealand
CPP	Customised Pricing-quality Path
CRP	Cost-Reflective Pricing
DG	Distributed Generation
DRC	Depreciated Replacement Cost
DUML	Distributed Unmetered Load
EA	the Electricity Authority
EV	Electric Vehicles
FENZ	Fire Emergency New Zealand
FMD	First Mover Disadvantage

Abbreviation	Definition
GXP	Grid Exit Point
HV	High Voltage
HVDC	High Voltage Direct Current
ICP	Installation Control Point, and is further defined in the Code
IR	Interconnection Rate
IRIS	Incremental Rolling Incentive Scheme
Km	Kilometre
kVA	kilovolt-ampere
kW	Kilowatt
kWh	kilowatt Hour
LFC	Low fixed charge
LPG	Liquid Petroleum Gas
LRMC	Long-Run Marginal Cost
LV	Low Voltage
Opex	Operating Expenditure
RAB	Regulatory Asset Base
RC	Replacement Cost
ROI	Return on Investment
SCADA	Supervisory Control and Data Acquisition
SFR	Subsidy Free Range
SONS	System Operations and Network Support
SRAM	Small Residue Allocation Methodology
SSDG	Small-scale Distributed Generation
ToU	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		60.00	60.00	¢/day
Daily Fixed Price (≤8kVA)	SHSD8		16.40	16.40	¢/day
Volumetric Price Component					
Anytime	010	11.38	1.48	12.86	¢/kWh
Peak	040	13.00	1.48	14.48	¢/kWh
Off-Peak	041	10.00	1.48	11.48	¢/kWh
All Inclusive: Anytime	017	7.30	1.48	8.78	¢/kWh
All Inclusive: Peak	042	8.71	1.48	10.19	¢/kWh
All Inclusive: Off-Peak	043	5.71	1.48	7.19	¢/kWh
Controlled	006	3.40	1.48	4.88	¢/kWh
Night Only	028	0.75	1.48	2.23	¢/kWh

A2. General Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Street Lighting Price Components					
Daily Fixed Price (SDN)	SDNSTL	334.78	190.56	525.34	$/ICP/day
Daily Fixed Price (SDNT)	SDNSTL	47.77	37.43	85.20	$/ICP/day
Daily Fixed Price (HWB)	HWBSTL	712.13	264.00	976.13	$/ICP/day
Daily Fixed Price (HWBT)	HWBSTL	39.79	14.75	54.55	$/ICP/day
Distributed Unmetered Load (DUML) Price Components					
Daily Fixed Price	SHSUNM	8.58		8.58	¢/ICP/day
Volumetric Price	030	3.07	1.48	4.55	¢/kWh
Load Group 0 (Unmetered Supply <1kVA Capacity) Price Components					
Daily Fixed Price	SH0	57.09	30.87	87.96	¢/day
Load Group 0A (Temporary Connection) Price Components					
Daily Fixed Price	SH0A	106.36	57.46	163.82	¢/day
Load Group 1A (≤8kVA Capacity) Price Components					
Daily Fixed Price	SH1A	6.47		6.47	¢/day
Capacity Price	SH1A	5.03	4.07	9.10	¢/kVA/day
CPD Price	SH1A	58.46	6.69	65.15	¢/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	6.47		6.47	¢/day
Capacity Price	SH1	3.01	4.35	7.36	¢/kVA/day
CPD Price	SH1	63.93	7.17	71.10	¢/kW/day
Load Group 2 (16-149kVA Capacity) Price Components					
Daily Fixed Price	SH2	12.76		12.76	¢/day
Capacity Price	SH2	3.72	5.83	9.55	¢/kVA/day
CPD Price	SH2	66.10	6.75	72.85	¢/kW/day
Load Group 3 (150-249kVA Capacity) Price Components					
Daily Fixed Price	SH3	177.86		177.86	¢/day
Capacity Price	SH3	7.48	11.16	18.64	¢/kVA/day
Distance Price	SH3	0.16		0.16	¢/kVA-km/day
CPD Price	SH3	53.07	5.68	58.75	¢/kW/day
Load Group 3A (250-499kVA Capacity) Price Components					
Daily Fixed Price	SH3A	177.86		177.86	¢/day
Capacity Price	SH3A	3.37	11.83	15.20	¢/kVA/day
Distance Price	SH3A	0.16		0.16	¢/kVA-km/day
CPD Price	SH3A	54.38	6.58	60.96	¢/kW/day
Load Group 4 (500-2,499kVA Capacity) Price Components					
Daily Fixed Price	SH4	489.34		489.34	¢/day
Capacity Price	SH4	0.62	12.63	13.25	¢/kVA/day
Distance Price	SH4	0.15		0.15	¢/kVA-km/day
CPD Price	SH4	45.13	5.77	50.90	¢/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	489.34		489.34	¢/day
Capacity Price	SH5	0.62	13.48	14.10	¢/kVA/day
Distance Price	SH5	0.15		0.15	¢/kVA-km/day
CPD Price	SH5	29.91	5.43	35.34	¢/kW/day
Equipment Price (if applicable)	SH5	70.00		70.00	¢/kVA/mth

Schedule B Central Otago / Wānaka Pricing Area

B1. Residential Connections	Code	(D) Distribution	(P) Pass-through	(D + P) Delivery	Units
Daily Price Component					
Daily Fixed Price (≤15kVA)	CCSD15		60.00	60.00	¢/day
Daily Fixed Price (≤8kVA)	CCSD8		16.40	16.40	¢/day
Volumetric Price Component					
Anytime	101	16.15	3.13	19.28	¢/kWh
Peak	140	18.72	3.13	21.85	¢/kWh
Off-Peak	141	13.72	3.13	16.85	¢/kWh
Controlled	106	5.71	3.13	8.84	¢/kWh
Night Only	108	4.49	3.13	7.62	¢/kWh
B2. General Connections	**Code**	**(D) Distribution**	**(P) Pass-through**	**(D + P) Delivery**	**Units**
Street Lighting Price Components					
Daily Fixed Price	CCSTL	3.02		3.02	¢/lamp/day
Volumetric Price	110	4.12	4.08	8.20	¢/kWh
Load Group 0 (Unmetered Supply <1kVA Capacity) Price Components					
Daily Fixed Price	CC0	61.32	106.03	167.35	¢/day
Load Group 0A (Temporary Connection) Price Components					
Daily Fixed Price	CC0A	104.93	216.78	321.71	¢/day
Load Group 1A (≤8kVA Capacity) Price Components					
Daily Fixed Price	CC1A	5.28		5.28	¢/day
Capacity Price	CC1A	5.71	2.29	8.00	¢/kVA/day
CPD Price	CC1A	75.33	1.96	77.29	¢/kW/day
Load Group 1 (≤15kVA Capacity) Price Components					
Daily Fixed Price	CC1	5.28		5.28	¢/day
Capacity Price	CC1	4.29	0.25	4.54	¢/kVA/day
CPD Price	CC1	82.31	0.11	82.42	¢/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	10.68		10.68	¢/day
Capacity Price	CC2	5.86	5.63	11.49	¢/kVA/day
CPD Price	CC2	55.76	8.32	64.08	¢/kW/day
Load Group 3 (150-249kVA Capacity) Price Components					
Daily Fixed Price	CC3	164.29		164.29	¢/day
Capacity Price	CC3	4.54	8.74	13.28	¢/kVA/day
Distance Price	CC3	0.11		0.11	¢/kVA-km/day
CPD Price	CC3	79.84	14.04	93.88	¢/kW/day
Load Group 3A (250-499kVA Capacity) Price Components					
Daily Fixed Price	CC3A	164.29		164.29	¢/day
Capacity Price	CC3A	0.91	4.65	5.56	¢/kVA/day
Distance Price	CC3A	0.11		0.11	¢/kVA-km/day
CPD Price	CC3A	98.78	3.75	102.53	¢/kW/day
Load Group 4 (500-2,499kVA Capacity) Price Components					
Daily Fixed Price	CC4	441.75		441.75	¢/day
Capacity Price	CC4	7.38	9.17	16.55	¢/kVA/day
Distance Price	CC4	0.10		0.10	¢/kVA-km/day
CPD Price	CC4	63.57	8.57	72.14	¢/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	441.75		441.75	¢/day
Capacity Price	CC5	4.03	6.11	10.14	¢/kVA/day
Distance Price	CC5	0.11		0.11	¢/kVA-km/day
CPD Price	CC5	72.33	18.77	91.10	¢/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		60.00	60.00	¢/day
Daily Fixed Price (≤8kVA)	FRSD8		16.40	16.40	¢/day
Volumetric Price Component					
Anytime	201	10.03	2.83	12.86	¢/kWh
Peak	240	12.10	2.83	14.93	¢/kWh
Off-Peak	241	8.10	2.83	10.93	¢/kWh
Controlled	206	2.66	2.83	5.49	¢/kWh
Night Only	208	1.63	2.83	4.46	¢/kWh
C2. General Connections	**Code**	**(D) Distribution**	**(P) Pass-through**	**(D + P) Delivery**	**Units**
Street Lighting Price Components					
Daily Fixed Price	FRSTL	3.51		3.51	¢/lamp/day
Volumetric Price	210	1.24	5.68	6.92	¢/kWh
Load Group 0 (Unmetered Supply <1kVA Capacity) Price Components					
Daily Fixed Price	FR0	45.26	79.83	125.09	¢/day
Load Group 0A (Temporary Connection) Price Components					
Daily Fixed Price	FR0A	73.58	84.14	157.72	¢/day
Load Group 1A (≤8kVA Capacity) Price Components					
Daily Fixed Price	FR1A	5.22		5.22	¢/day
Capacity Price	FR1A	3.96	4.35	8.31	¢/kVA/day
CPD Price	FR1A	40.41	7.36	47.77	¢/kW/day
Load Group 1 (≤15kVA Capacity) Price Components					
Daily Fixed Price	FR1	5.22		5.22	¢/day
Capacity Price	FR1	2.10	6.73	8.83	¢/kVA/day
CPD Price	FR1	42.74	9.47	52.21	¢/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	7.92		7.92	¢/day
Capacity Price	FR2	3.83	6.43	10.26	¢/kVA/day
CPD Price	FR2	46.30	8.92	55.22	¢/kW/day
Load Group 3 (150-249kVA Capacity) Price Components					
Daily Fixed Price	FR3	143.25		143.25	¢/day
Capacity Price	FR3	15.24	10.69	25.93	¢/kVA/day
Distance Price	FR3	0.09		0.09	¢/kVA-km/day
CPD Price	FR3	49.04	0.04	49.08	¢/kW/day
Load Group 3A (250-499kVA Capacity) Price Components					
Daily Fixed Price	FR3A	143.25		143.25	¢/day
Capacity Price	FR3A	13.93	10.34	24.27	¢/kVA/day
Distance Price	FR3A	0.09		0.09	¢/kVA-km/day
CPD Price	FR3A	50.45	0.10	50.55	¢/kW/day
Load Group 4 (500-2,499kVA Capacity) Price Components					
Daily Fixed Price	FR4	401.27		401.27	¢/day
Capacity Price	FR4	3.54	12.65	16.19	¢/kVA/day
Distance Price	FR4	0.09		0.09	¢/kVA-km/day
CPD Price	FR4	29.28	8.82	38.10	¢/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	401.27		401.27	¢/day
Capacity Price	FR5	1.29	4.14	5.43	¢/kVA/day
Distance Price	FR5	0.18		0.18	¢/kVA-km/day
CPD Price	FR5	20.45	12.61	33.06	¢/kW/day
Equipment Price (if applicable)	FR5	70.00		70.00	¢/kVA/mth

SCHEDULE D QUEENSTOWN PRICING AREA (FRANKTON SUB-AREA)

		(D)	(P)	(D + P)	
D1. Residential Connections	**Code**	**Distribution**	**Pass-through**	**Delivery**	**Units**
Daily Price Component					
Daily Fixed Price (≤15kVA)	FKSD15		60.00	60.00	¢/day
Daily Fixed Price (≤8kVA)	FKSD8		16.40	16.40	¢/day
Volumetric Price Component					
Anytime	301	10.03	2.83	12.86	¢/kWh
Peak	340	12.10	2.83	14.93	¢/kWh
Off-Peak	341	8.10	2.83	10.93	¢/kWh
Controlled	306	2.66	2.83	5.49	¢/kWh
Night Only	308	1.63	2.83	4.46	¢/kWh
		(D)	**(P)**	**(D + P)**	
D2. General Connections	**Code**	**Distribution**	**Pass-through**	**Delivery**	**Units**
Street Lighting Price Components					
Daily Fixed Price	FKSTL	3.51		3.51	¢/lamp/day
Volumetric Price	310	1.24	5.68	6.92	¢/kWh
Load Group 0 (Unmetered Supply <1kVA Capacity) Price Components					
Daily Fixed Price	FK0	45.26	79.83	125.09	¢/day
Load Group 0A (Temporary Connection) Price Components					
Daily Fixed Price	FK0A	73.58	84.14	157.72	¢/day
Load Group 1A (≤8kVA Capacity) Price Components					
Daily Fixed Price	FK1A	5.22		5.22	¢/day
Capacity Price	FK1A	3.96	4.35	8.31	¢/kVA/day
CPD Price	FK1A	40.41	7.36	47.77	¢/kW/day
Load Group 1 (≤15kVA Capacity) Price Components					
Daily Fixed Price	FK1	5.22		5.22	¢/day
Capacity Price	FK1	2.10	6.73	8.83	¢/kVA/day
CPD Price	FK1	42.74	9.47	52.21	¢/kW/day

		(D)	(P)	(D + P)	
D2. General Connections	**Code**	**Distribution**	**Pass-through**	**Delivery**	**Units**
Load Group 2 (16-149kVA Capacity) Price Components					
Daily Fixed Price	FK2	7.13		7.13	¢/day
Capacity Price	FK2	3.45	5.79	9.24	¢/kVA/day
CPD Price	FK2	41.67	8.02	49.69	¢/kW/day
Load Group 3 (150-249kVA Capacity) Price Components					
Daily Fixed Price	FK3	118.18		118.18	¢/day
Capacity Price	FK3	12.57	8.82	21.39	¢/kVA/day
Distance Price	FK3	0.07		0.07	¢/kVA-km/day
CPD Price	FK3	40.46	0.03	40.49	¢/kW/day
Load Group 3A (250-499kVA Capacity) Price Components					
Daily Fixed Price	FK3A	118.18		118.18	¢/day
Capacity Price	FK3A	11.49	8.53	20.02	¢/kVA/day
Distance Price	FK3A	0.07		0.07	¢/kVA-km/day
CPD Price	FK3A	41.62	0.08	41.70	¢/kW/day
Load Group 4 (500-2,499kVA Capacity) Price Components					
Daily Fixed Price	FK4	310.98		310.98	¢/day
Capacity Price	FK4	2.74	9.80	12.54	¢/kVA/day
Distance Price	FK4	0.07		0.07	¢/kVA-km/day
CPD Price	FK4	22.69	6.84	29.53	¢/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	310.98		310.98	¢/day
Capacity Price	FK5	1.00	3.21	4.21	¢/kVA/day
Distance Price	FK5	0.14		0.14	¢/kVA-km/day
CPD Price	FK5	15.85	9.77	25.62	¢/kW/day
Equipment Price (if applicable)	FK5	70.00		70.00	¢/kVA/mth

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. 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.

8. For L4 and L5 load groups an additional $8.40 per kVA of capacity applies if Aurora Energy owns the distribution transformer.

9. An additional $85.20 per kVA per annum of equivalent corrective capacitance applies if the installation power factor is required to be improved to 0.95.

10. Settlement residues are excluded from pass-through prices and are credited separately (refer section 7.2).

11. The registry code of "NOCHARGE" applies to Aurora Energy ICPs that do not incur any delivery prices.

12. 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.

13. The All-Inclusive volumetric price options (codes "017", "042", and "043") 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.

14. 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		CPD kw Discount
		Residential	General	Residential	General	Residential	General	Residential	General	
IN19	All Inclusive	017	017$ND							42%
UN24	Anytime	010	010$ND	101	101$ND	201	201$ND	301	301$ND	Nil
PK	Anytime	040	040$ND	140	140$ND	240	240$ND	340	340$ND	Nil
OP	Anytime	041	041$ND	141	141$ND	241	241$ND	341	341$ND	Nil
PK	All Inclusive	042	042$ND	140	140$ND	240	240$ND	340	340$ND	Nil
OP	All Inclusive	043	043$ND	141	141$ND	241	241$ND	341	341$ND	Nil
CN11	Controlled >8	006	006$ND	106	106$ND	206	206$ND	306	306$ND	50%
CN8	Night Only	028	028$ND	108	108$ND	208	208$ND	308	308$ND	100%
IN16	All Inclusive	010	010$ND							Nil
IN8	All Inclusive	041	041$ND							Nil
CN20	Controlled >8			106	106$ND	206	206$ND	306	306$ND	50%
CN16	Controlled >8	006	006$ND	106	106$ND	206	206$ND	306	306$ND	50%
CN13	Controlled >8			106	106$ND	206	206$ND	306	306$ND	50%
CN10	Controlled >8				145$ND		245$ND		345$ND	100%
DC16	Anytime	010	010$ND							Nil
NC8	Anytime	041	041$ND							Nil
D16	Anytime	010	010$ND	101	101$ND	201	201$ND	301	301$ND	Nil
N8	Anytime	041	041$ND	141	141$ND	241	241$ND	341	341$ND	Nil
EG24 (Dist. Generation)		090	090$ND	190	190$ND	290	290$ND	390	390$ND	Nil

Appendix D. Customer Examples

The level of pricing change for consumers will differ depending on which pricing area the consumer is situated in, and their consumption patterns. This appendix provides worked examples to demonstrate how the most common residential price components in each pricing area are calculated, and then applied to an average customer consuming 9,000 kWh per year.

The worked examples provided in this appendix follow the pricing approach outlined in section 3.5 of this Pricing Methodology document. Table 13, below, provides an overview of each of the steps required to calculate the price components.

Table 13: Steps required to calculate price components.

Step name	Description
1. Forecast allowable revenue	The maximum annual revenue Aurora Energy can earn is determined by the Commerce Commission. Section 3.4 of this document details the components of forecast allowable revenue used in the price-setting process.
2. Allocate revenue to pricing areas	The forecast allowable revenue is allocated to each of the pricing areas based on the underlying costs of supplying services to that pricing area. Section 3.5 of this document provides more detail about the pricing area allocation methodology.
3. Allocate revenue to load groups	Within each pricing area the forecast allowable revenue is further allocated to each customer load group. Section 3.6 of this document provides more detail about the load group allocation methodology.
4. Allocate revenue to price components	Within load groups in each pricing area, forecast allowable revenue is allocated to price components that reflect the impact of customers' consumption decisions on the key drivers of costs. For example, residential customers will incur a daily fixed charge and variable volumetric charges that reflect whether the energy consumed is controlled or uncontrolled. The allocation of revenue to fixed price components is currently limited by the Electricity (Low Fixed charge Tariff Option for Domestic Consumers) Regulations 2004, which are being phased out over five years. The phasing out of these regulations aligns with the strategy to recover prices in a more cost-reflective manner. As a result of this strategy, Aurora Energy is anticipating changes to the way revenue is allocated to price components over the next three to four pricing years.

5. Forecast quantities	For each price component in each pricing area, Aurora Energy prepares a forecast of expected quantities for the pricing year. The forecast quantities are calculated by applying historic growth trends to current volumes. By 31 March each year, an annual Price-Setting statement is published on the Aurora Energy website which provides more detail about the forecast quantities and the methodology used to prepare the forecasts.
6. Calculate price components	For each price component in each pricing area, we divide the revenue calculated in step 4, by the forecast quantities in step 5.

D.1 Dunedin Residential Consumer

Historically, Aurora Energy offered an all-inclusive tariff for Dunedin customers to recognise that the cost of providing separate metering to measure controlled and uncontrolled usage outweighed the benefit. With the evolution of smart meters, the cost of providing separate metering is no-longer significant. Accordingly, the all-inclusive tariff for Dunedin has not been offered to new customers since 1 April 2017. Customers who connected to the Aurora Energy network prior to 1 April 2017 are still entitled to the all-inclusive tariff options. The example provided in Table 14 reflects that the all-inclusive tariffs remain the most commonly applied tariff type in the Dunedin pricing area.

D.1.1. Calculation of price components applicable to an average residential consumer in Dunedin

Figure 14 below, describes how the steps outlined in Table 13 above, are applied to calculate the daily fixed price for residential customers along with the most common residential variable price components in the Dunedin pricing area.

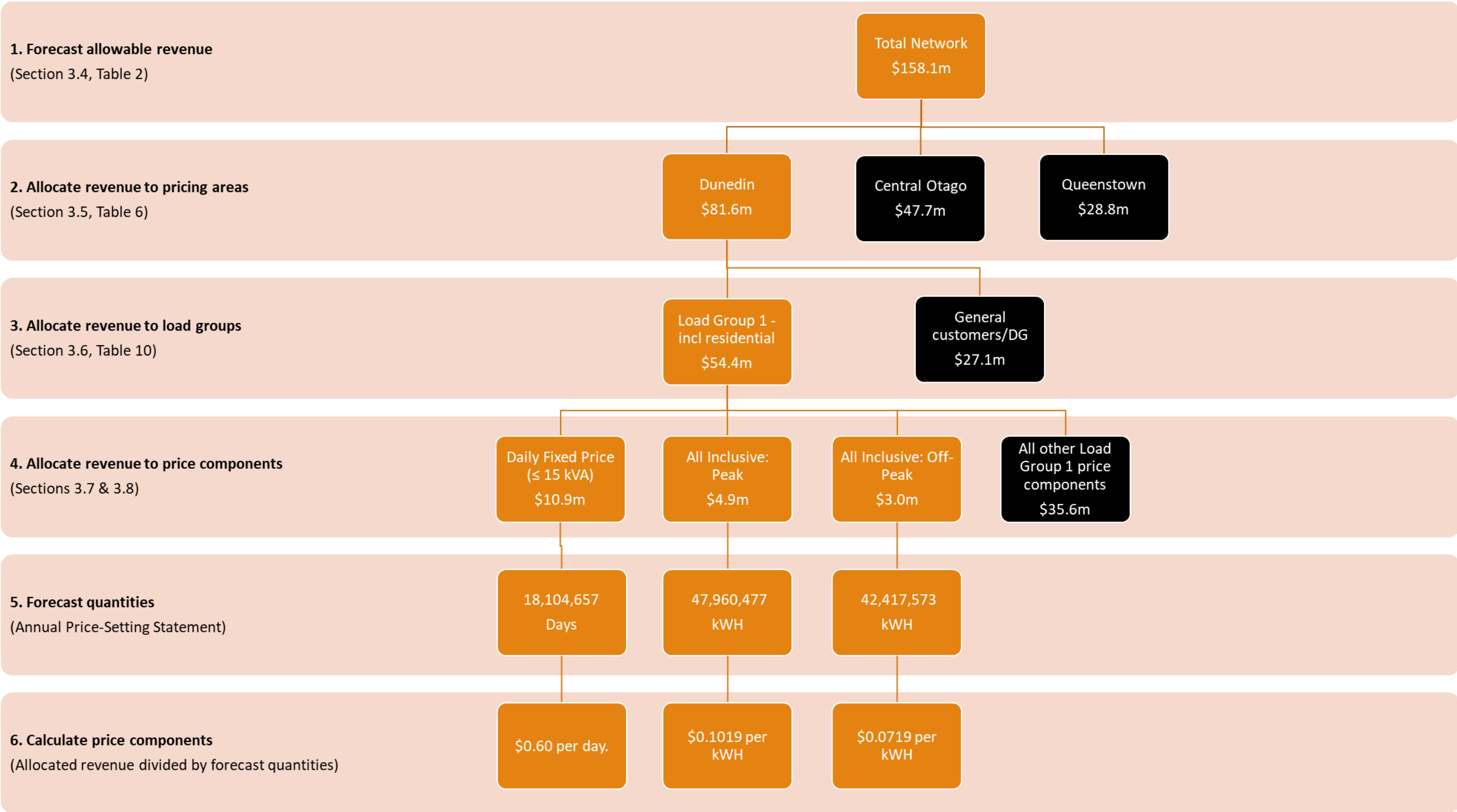
D.1.2. Application of price components to an average residential consumer in Dunedin

Table 14 below, uses the price components calculated in Figure 14 to calculate the annual line charges for a typical residential consumer in Dunedin that consumes 9,000kW of electricity annually. The price components selected represent the most common price components used in Dunedin and the split between summer and winter consumption reflects the average usage patterns of residential consumers in Dunedin.

Table 14 Application of tariffs to a typical Dunedin residential consumer

Tariff	kWh	Unit price RY24	Unit price RY25	Average monthly charge RY24	Average monthly charge RY25
Daily Fixed Price (≤15kVA)		$0.4500	$0.6000	$13.73	$18.25
All Inclusive: Peak	4,443	$0.0835	$0.1019	$30.92	$37.73
All Inclusive: Off-Peak	4,557	$0.0835	$0.0719	$31.71	$27.30
GST				$11.45	$12.49
Average Monthly Charge				**$87.80**	**$95.77**
Annual % Increase					9.1%

Figure 14 Calculation of tariffs applicable to a typical residential consumer in Dunedin



D.2 Central Otago/Wānaka Residential Consumer

D.2.1. Calculation of price components applicable to an average residential consumer in Central Otago and Wānaka

Figure 15, describes how the steps outlined in Table 13 above, are applied to calculate the daily fixed price for residential customers along with the most common residential variable price components.

D.2.2. Application of price components to an average residential consumer in Central Otago and Wānaka

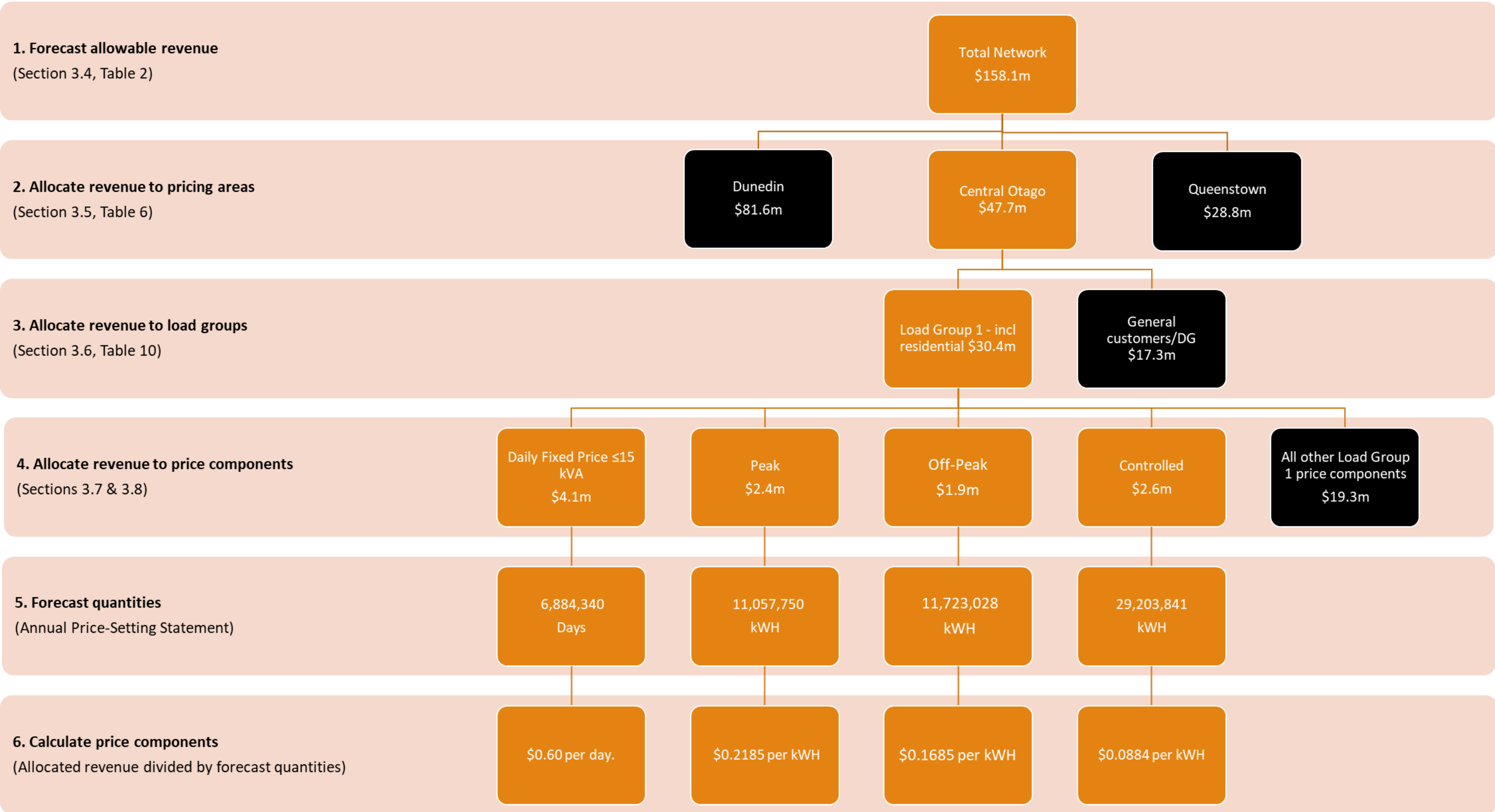
Table 15 below, uses the price components calculated in Figure 15 to calculate the annual line charges for a typical residential consumer in Central Otago and Wānaka that consumes 9,000kW of electricity annually. The price components selected represent the most common price components used in Central Otago and Wānaka.

Based on the forecast quantities for RY25 we expect 21% of the typical residential customer's consumption to be subject to control, and 79% of the typical customer's consumption to be uncontrolled. The uncontrolled split between summer and winter consumption reflects the average usage patterns of residential consumers in Central Otago and Wānaka.

Table 15 Application of tariffs to a typical Central Otago and Wānaka residential consumer

		Unit price		Average monthly charge	
Tariff	kWh	RY24	RY25	RY24	RY25
Daily Fixed Price (≤15kVA)		$0.4500	$0.6000	$13.73	$18.25
Peak	3,469	$0.1867	$0.2185	$53.97	$63.16
Off-Peak	3,678	$0.1867	$0.1685	$57.22	$51.65
Controlled	1,853	$0.0800	$0.0884	$12.35	$13.65
GST				$20.59	$22.01
Average Monthly Charge				**$157.86**	**$168.72**
Annual % Increase					6.9%

Figure 15 Calculation of tariffs applicable to a typical residential consumer in Central Otago and Wānaka



D.3 QUEENSTOWN RESIDENTIAL CONSUMER

D.3.1. Calculation of price components applicable to an average residential consumer in Queenstown

Figure 16, describes how the steps outlined in Table 13, are applied to calculate the daily fixed price for residential customers along with the most common residential variable price components.

D.2.2. Application of price components to an average residential consumer in Queenstown

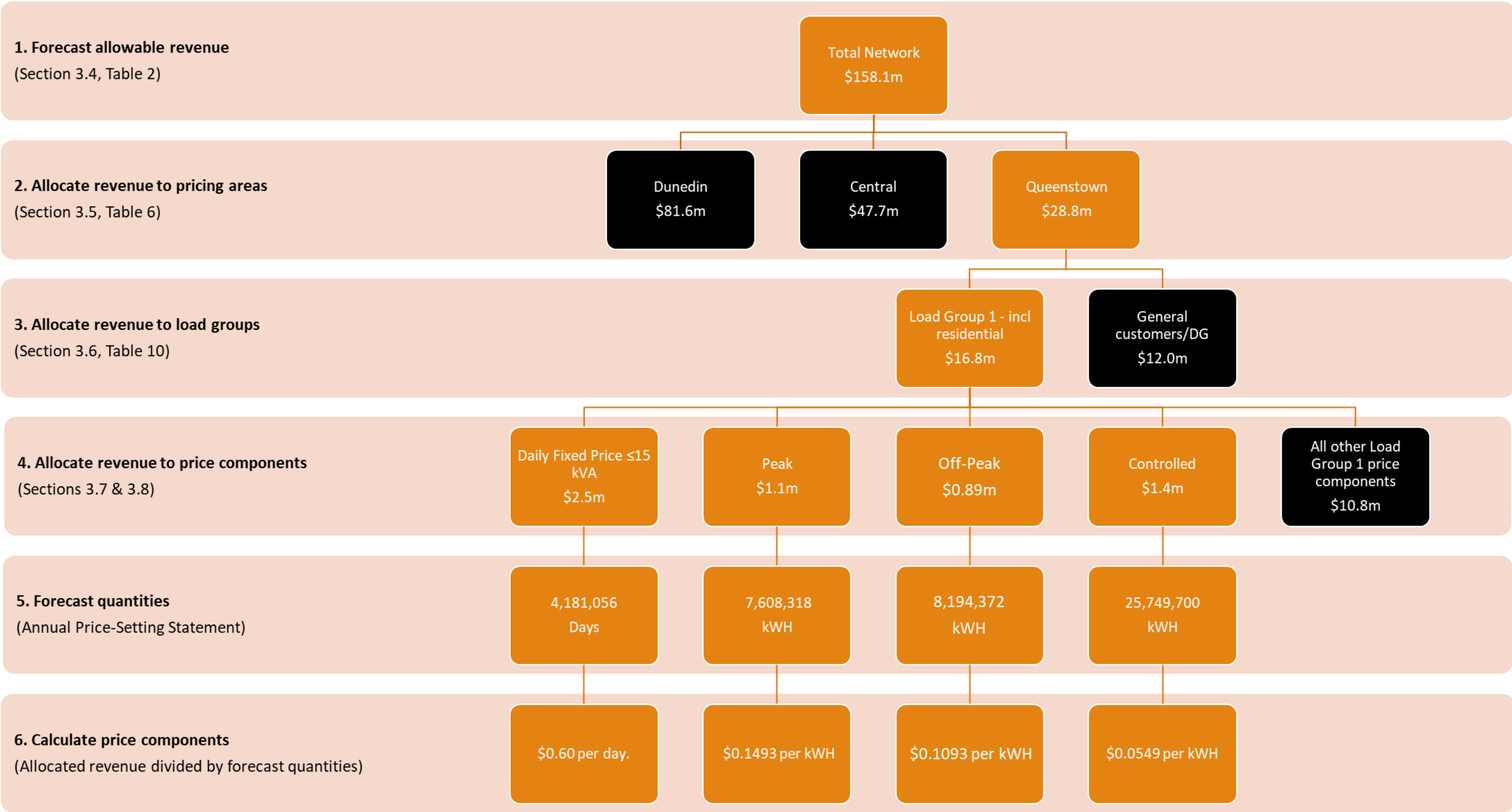
Table 16 below, uses the price components calculated in Figure 16, to calculate the annual line charges for a typical residential consumer in Queenstown. The price components selected represent the most common price components used in Queenstown.

Based on the forecast quantities for RY25 we expect 22% of the typical residential customer's consumption to be subject to control, and 78% of the typical customer's consumption to be uncontrolled. The uncontrolled split between summer and winter consumption reflects the average usage patterns of residential consumers in Queenstown.

Table 16 Application of tariffs to a typical Queenstown residential consumer

		Unit price		Average monthly charge	
Tariff	kWh	RY24	RY25	RY24	RY25
Daily Fixed Price (≤15kVA)		$0.4500	$0.6000	$13.73	$18.25
Peak	3,370	$0.1240	$0.1493	$34.82	$41.93
Off-Peak	3,630	$0.1240	$0.1093	$37.51	$33.06
Controlled	2,000	$0.0473	$0.0549	$7.88	$9.15
GST				$14.09	$15.36
Average Monthly Charge				**$108.03**	**$117.75**
Annual % Increase					9.0%

Figure 16 Calculation of tariffs applicable to a typical residential consumer in Queenstown



Appendix E. ALIGNMENT TO PRICING PRINCIPLES

Outlined below is a review of the pricing for alignment with the Electricity Authority's 2019 pricing principles. Each principle is examined to include an interpretation, assessment against current alignment, and potential alignment improvements as the strategy is implemented.

E.1. COST SIGNALLING

There are four principles focussed on aspects of cost signalling.

E.1.1. Subsidy Free

(a)	Prices are to signal the economic costs of service provision, including by: (i) being subsidy free (equal to or greater 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.

The term *consumer group* is not used at present, but it is equivalent to the 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 17 assesses current (RY25) alignment, and how that will change as the strategy is implemented and movement is made towards the target pricing arrangements.

Table 17: Subsidy free assessment

Element	Current state	Target state
Subsidy-free pricing areas	Over the past two pricing years improvements have been made to the pricing area cost allocations. RAB values are now used as the basis for allocating capital costs (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.	No further changes required.
Subsidy-free consumer groups	Estimates are available 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.	More complete estimates will be developed of the subsidy-free ranges at a consumer group level. As pricing levels are rebalanced, Aurora Energy will ensure revenue from each consumer group falls within the range.

E.1.2. Economic Costs

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

(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 kVA 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 18: Economic cost signalling assessment

Element	Current state	Target state
Economic cost signalling	Some signalling is provided through controlled rates for small consumers. For large consumers, signalling is provided through capacity prices, control period demand prices and corrective capacitance charges. The Aurora Energy Capital Contributions Policy also provides some signalling at the time of installation (or upgrade).	Aurora Energy aims to improve the targeting of peak pricing periods, and better calibrate signal strength based on LRMC studies. Improved calibration will apply across peak, off-peak, and managed load discounts. An injection charge may also be considered if the LRMC is strong enough to warrant this step.

E.1.3. Services

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

(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 19: Service based pricing assessment

Element	Current state	Target state
Service-based pricing	Like most electricity networks, Aurora Energy do not currently offer options for differentiated service levels. The Capital Contributions Policy encourages customers to make their own trade-offs where relevant.	No change.

E.1.4. Network Alternatives

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

(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 –a transmission alternative may be proactively encouraged as an option for addressing an emerging capacity or security constraint. This may require specific prices to be set 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 20: Network alternatives assessment

Element	Current state	Target state
Network alternatives	Aurora Energy provides some signalling through the current pricing but targeting and calibration could be improved. Specific pricing arrangements are being put in place as part of a tactical network alternatives trial in the upper part of the Aurora Energy Clutha network.	Improved targeting and calibration at a pricing area level.

E.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 21: Residual costs recovery assessment

Element	Current	Target
Residual	A low fixed charge for all residential consumers is set. 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, there is 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 revenue is recovered through usage-based charge components.	Aurora Energy will have usage-based charges structured to signal modelled LRMC and 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. It is expected that allocated residual costs will primarily be recovered through fixed charges, (though may supplement these with low and broad usage charges). The phase-out of the LFC requirements complements the plans to gradually increase the share of residual costs recovered through fixed charges.

E.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 22: Responsiveness assessment

Element	Current	Target
Responsiveness	Aurora Energy offer individual pricing for large customers with specialised needs. This allows scope for price-quality trade-offs. Prices have been adjusted for large customers in Frankton who may otherwise opt for uneconomic bypass.	It is expected that these existing features will be retained. Aurora Energy will 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.

E.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 the ongoing reform of pricing, including:

- transparency – is clear information provided on how pricing works, the plans and rationale for change, and the likely impact on customers?
- transaction costs – will change be difficult or costly for retailers to implement and for 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 23: Development assessment

Element	Assessment
Transparency	In April 2021 the pricing strategy and roadmaps to complement our Pricing Methodology were published. In response to additional CPP-related information disclosure requirements, Aurora Energy has included worked customer examples in the Pricing Methodology and a copy of the CoSM has been published on the Aurora Energy website.

Element	Assessment
Transaction costs	ToU pricing is more complex than the existing pricing, so we have improved our web based content to communicate how it works. It is planned to consult on price components, including the best option for larger consumers that balances complexity and efficiency. It is planned to consult regularly as reforms are implemented over the next few years.
Consumer impacts	We are monitoring the impacts of the transition to cost reflective pricing, with particular emphasis on those consumers in the highest deprivation households.
Uptake incentives	ToU pricing has been implemented by several distributors now, and uptake amongst retailers is improving. Aurora Energy intend to explore options for accommodating consumers who do not have suitable metering while nonetheless encouraging uptake.

Appendix F. Compliance Matrix

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

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 3.1 and 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 7.1 and 9
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 3.2
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 3.8
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 E
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 components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;	Clause 2.4.3(4)	Section 3.7, Section 3.8, 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 3.1
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 component as publicly disclosed under clause 2.4.18.	Clause 2.4.3(8)	Section 3.8
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 2.10
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)	No change to the strategy this year.
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 7.1

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 7.1
how the EDB determines whether to use a non-standard contract, including any criteria used;	Clause 2.4.5(1)(b)	Section 7.1
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 7.1
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 7.1
any implications of this approach for determining prices for consumers subject to non-standard contracts;	Clause 2.4.5(2)(b)	Section 7.1
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 9
prices; and	Clause 2.4.5(3)(a)	Section 9.3
value, structure and rationale for any payments to the owner of the distributed generation.	Clause 2.4.5(3)(b)	Section 9.3
Every disclosure by Aurora Energy under clauses 2.4.1 and 2.4.2 must include:	Clause 2.4.5A	
Together with the information disclosed under clauses 2.4.1(1) and 2.4.2, sufficient information and commentary in a readily understandable form to enable interested persons to understand how Aurora Energy has set prices for each Aurora Energy pricing region;	Clause 2.4.5A(1)	Section 3.5 and Appendix D

Information Disclosure Requirement	Determination Reference	Pricing Methodology Reference
For each Aurora Energy pricing region, a worked example of how an average domestic consumer's prices would be calculated; and	Clause 2.4.5A(2)	Appendix D
A version of Aurora Energy's cost of supply model with explanatory material that will assist interested persons to understand how the cost of supply model works.	Clause 2.4.5A(3)	A copy of the CoSM can be found at www.auroraenergy.co.nz

Appendix G. Directors' Certificate

SCHEDULE 17[5]

Certification for Year-beginning Disclosures

(Pricing Methodology Only)

Clause 2.9.1 of section 2.9

We Stephen Richard Thompson and Janice Evelyn Fredric, 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

Janice Evelyn Fredric

27 March 2024

Dated

5 Electricity Distribution Information Disclosure Determination 2012.

Aurora
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