Methodology for deriving delivery prices

For prices applying from 1 April 2021

Issued 25 February 2021

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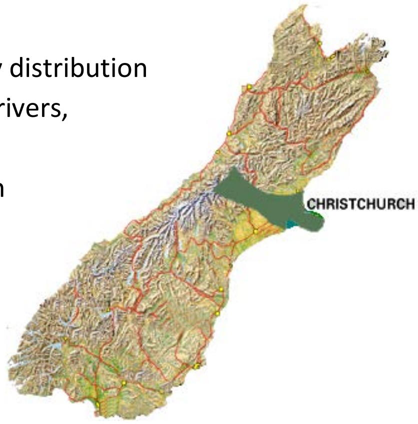
Glossary of abbreviations

The following abbreviations are used in this document:

- **ADMD,** for *after diversity maximum demand*. Customers[1] within each connection category use electricity at different times – a high load from one customer is often offset by others with low load – and we assess the maximum of this "diversified" loading. For distribution assessments we consider the ADMD at times when the local network supplying the load is peaking, for transmission assessments we consider the ADMD of each category at times when the overall network is peaking.
- **ΣAMD,** for *sum of anytime maximum demands*. This is the sum of the individual peaks (occurring at different times) of the connections in a category.
- **CPP,** for *customised price-quality path.* An alternative to the default form of price regulation administered by the Commerce Commission. Applied to Orion from April 2014 to March 2019.
- **DPP,** for *default price-quality path.* This is the form of price regulation that applied to Orion up to 31 March 2014 and applies from 1 April 2019.
- **IRIS***,* for *Incremental Rolling Incentive Scheme.*
- **LRAIC,** for *long run average incremental cost*. See the definition and discussion in section 7 and the derivation in Appendix E.
- **ODRC,** for *optimised depreciated replacement cost*. This is a measure of the depreciated value of assets, based on replicating the network, using modern equivalent assets and an efficient design.
- **ODV,** for *optimised deprival value*. This is the total value of assets that allows the network to operate in an efficient, long term commercially sustainable way.
- **RIV,** for *regulatory investment value*. This represents the indexed depreciated regulatory value of assets (the regulatory asset base, or RAB) with deferred tax adjustments.
- **TPM,** for *transmission pricing methodology*. This is the methodology that Transpower follows in setting the prices and charges applicable to its customers.
- **VOLL,** for *value of lost load.* This is the amount that we assess customers in each connection category are willing to pay (on average) to avoid a power cut.
- **WACC,** for *weighted average cost of capital*. As determined by the Commerce Commission for setting allowable revenue and against which Orion's actual returns are compared and assessed.

[1] In this document we generally use the term "customer" to refer to end consumers. Some references to external documents use the term "consumer", for example the references to the distribution pricing principles. We consider the terms to be interchangeable.

1 Introduction



New Zealand’s South Island

Orion New Zealand Limited (Orion) owns and operates the electricity distribution network in central Canterbury between the Waimakariri and Rakaia rivers, and from the Canterbury coast to Arthur’s Pass. Our network covers 8,000 square kilometres of diverse geography, including Christchurch city, Banks Peninsula, farming communities and high country regions. We receive electricity from Transpower’s national grid at 7 different locations[2] and we distribute this electricity to more than 210,000 homes and businesses.

Our service covers the delivery of electricity only - we do not buy and sell electricity, we simply deliver it to the customers of electricity retailers that operate in our area. We charge electricity retailers on a wholesale basis for this delivery service. Electricity retailers, in turn, include this cost in their retail electricity prices - our delivery charges amount to 35% of an average household’s electricity bill.

Our network is entirely within the boundaries of the two local councils that own Orion, Christchurch City Council (which owns 89.3%) and Selwyn District Council (which owns 10.7%).

Our network is a natural monopoly: it’s economically sensible to support one electricity network in the region and avoid the cost of duplicating the service, including in areas where physical space is a constraint. As a result, we are not exposed to the competitive pressures that drive improved efficiencies and service levels in other markets. As a surrogate for these competitive pressures, the government has developed regulations for electricity network owners under Part 4 of the the Commerce Act 1986 (the Act). The Act is administered by the Commerce Commission (the Commission).

The Act requires Orion to:

- limit delivery price increases, while maintaining quality of supply; and
- disclose certain information about our business, including this pricing methodology statement.

The purpose of information disclosure is to promote efficient operation of electricity distribution businesses by requiring electricity distributors to make publicly available reliable and timely information about the operation and behaviour of their businesses. This helps to inform a wide range of people about such factors as profits, costs, asset values, price, quality, security and reliability. It therefore supports assessment of whether the purpose of the Act is being met.

[2] A small (but growing) amount of energy also enters the network from connections that have generation capability, such as solar panels.

2 Pricing principles, objectives and strategy

We aim to set prices that provide sufficient revenue to cover all our costs, including pass-through and recoverable costs (primarily transmission costs) and our cost of capital, while seeking to comply with the regulations. The structure of our pricing aims to reflect the economic costs of providing our delivery service. With this approach, customers can make efficient decisions about which form of energy to use and when to use it, which contributes to economic welfare, and facilitates an efficient transition to a low carbon economy.

Recognising these high level objectives, the following considerations influence our pricing. There is often a trade-off between these various considerations.

2.1 Economic considerations

In terms of the structure of our pricing, we aim to ensure that our pricing is economically efficient, which means that:

- customers choosing to use our network should face the appropriate cost of that decision and be incentivised to weigh up the value of the service and the cost of alternatives, and consequently
- investments in our network over time will be at an appropriate level and in the interest of customers.

The key economic input to our pricing is the long run average incremental cost (LRAIC) of investment in our network on the basis that, if customers are prepared to pay prices that reflect LRAIC, then further investment in network capacity is economically efficient. We apply this concept consistently in our pricing across the various groups, and in particular via the 'peak' components which reflect the network capacity that we provide to meet demand at times of congestion.

Our derivation and application of LRAIC is described in more detail in section 7 and Appendix E.

2.2 Default price-quality path

In terms of the level of prices, Orion is subject to the default price-quality path (DPP) set by the Commerce Commission which applies to all non-exempt distributors (that are not on a customised price-quality path). The Commerce Commission "reset" the DPP to apply for a 5-year regulatory period starting 1 April 2020, and prices applying in the second year of this regulatory period are the subject of this methodology.

Orion must set delivery prices consistent with allowable revenues determined by the Commission under the DPP. Allowable revenues provide for a return on investment (referred to as a weighted average cost of capital, or WACC), as well as allowances for depreciation, administration, operating and maintenance expenditure, performance incentives and pass-through costs.

The detail of how our prices comply with the DPP is set out in our separate annual price setting compliance statement (and is not repeated here). In this pricing methodology the limits imposed by the DPP manifests as a simple adjustment to our return on investment so that the resulting prices comply with the limit set in the price path.

2.3 Even-handedness and practical considerations

Orion takes into account the need for even-handedness and practicality in determining customer groupings, cost allocations and the structure of our pricing. Specifically we:

- apply price averaging over large groups of connections, because it is generally not practical to single out individual connections for cost-specific delivery pricing. However, where it is practical we do allocate assets and associated costs only to the connections or connection categories that use them,
- recognise that all customers should share in the benefits of greater utilisation of shared assets and other enhanced economies of scale (new customers are not gifted existing capacity, instead the costs of significant upgrades are spread across new and existing customers that share in their use),
- recognise that customers change their demand behaviour only over relatively long periods of time and it is important that we provide compelling and consistent pricing incentives aimed at maximising the efficient utilisation of our assets,
- seek to make our price signals effective by balancing strong price signals with easily understood application and measurement,
- treat connections with similar electrical attributes consistently,
- set prices that are the same for all retailers, providing a "level playing field" to promote retail competition.

2.4 Other regulatory considerations

The principal regulatory requirement that we seek to comply with is the price-quality path set for us by the Commission as described above.

We also consider other regulatory and policy requirements, and in particular:

- the information disclosure requirements (as they relate to pricing) promulgated by the Commission in October 2012 (a cross-referencing of this methodology to the information disclosure requirements is included in Appendix B),
- the distribution pricing principles and associated practice note published by the Electricity Authority (the "Authority"). Our assessment of Orion's alignment with these is included in Appendix B,
- the Authority's views on the need for distributors to develop and publish plans for how they intend to implement 'service-based' and 'cost-reflective' pricing. We have set out our current plans for possible future pricing changes in Appendix C,
- the Low Fixed Charge regulations that require us to provide pricing options with low fixed charges for residential customers, and
- the regulations relating to the connection of distributed generation.

We note that both key pieces of governing legislation that relate to pricing - the Commerce Act 1986 and the Electricity Industry Act 2010 - are aimed at ensuring the long term interests of consumers are met.

Our pricing strategy (see section 2.7 below) encapsulates our pricing principles and objectives as set out in this section and should be read in conjunction with them.

2.5 Changes to the methodology

Last year we introduced a sustainability consideration to our pricing strategy, which, initially, influences our assessment of the trade-offs when we adjust different components of our pricing. We also tied in a recognition of our capital contribution requirements for new connections to provide a more holistic view of the total revenue over the lifecycle of connections and the locational aspect that comes with this.

This year we have not made any changes to our pricing strategy, other than to adjust the wording to better reflect the current context, and to reference the aspects that we expect will significantly influence our pricing in the next few years. This year we have updated our prices within the existing methodology framework.

2.6 Customer consultation

The information disclosure requirements include a requirement regarding the extent to which the views of customers in terms of price and quality have been sought and reflected in the price-setting process.[3]

In terms of price structure, we undertake consultation when we propose any changes to our pricing. The last such consultation occurred in September and October 2018. At that time the views expressed by stakeholders broadly supported our proposals and we introduced a range of changes from April 2019 (most notably, the introduction of a universal fixed charge for all connections in our general category).

This consultation also sought views on our longer term pricing reform, and has informed our direction for possible future pricing changes as set out in Appendix C.

We have also consulted with customers, by way of focus groups, on the challenges of having prices based largely on volumes when supply costs are fixed, and particularly in the context of the impact this has on adoption of new technologies, such as electric vehicles and solar PV. This consultation informed our decision to implement a fixed charge for general connections in 2019.

In addition, we have established a customer advisory panel to assist us in, amongst other things, considering price quality trade-offs inherent in our network investment and operation. To date, the main take-out from this initiative is a view that energy affordability is important, and that we need to address the burden on low income customers and the negative impact this has on their lives. At the same time, the panel express a high level of satisfaction with our current level of reliability.

More generally, we are always open to comments on our pricing from any party, and in particular we present our prices to retailers each year as proposed prices that they are able to comment on.

[3] Commerce Commission, Decision NZCC 22: Electricity Distribution Information Disclosure Determination 2012, 2.4.1 (4). The Determination uses the term consumer rather than customer.

In addition to our pricing consultation, and with a particular focus on price-quality trade offs, we look to the consultation that is undertaken as part of our asset management plan (AMP) process. This process allows consideration of meaningful trade-offs between our investment and asset management decisions (which are our key cost drivers) and the associated future quality of the delivery service. To the extent that the consultation impacts on our investment and operating expenditure this will, over time, be reflected in changes in the real prices that customers pay, and the quality of supply they receive

2.7 Pricing strategy

Our high level pricing strategy was formally approved by the Orion board at its meeting on 9 December 2020. The strategy, with changes from the previous strategy marked, is as follows[4]:

Our delivery pricing strategy

We aim to set our delivery prices to provide sufficient revenue to recover our prudent and efficient costs, including our cost of capital as determined under the~~. We also aim to comply with the~~ price control regulations that apply to us.

We aim to reflect the long term economic costs of providing consumers with the quality of delivery service that they require. Cost recovery is fundamental to retaining our incentives to invest in our network in the long term interests of consumers. In structuring and setting our prices we take a medium to long term view, and we consider economic efficiency, equity and practicality. We seek to ensure that our pricing is economically efficient, which means that customers who use our network face the appropriate cost of that use, and are incentivised to weigh up the value of our delivery service and the alternatives. Cost reflective prices should help to ensure that our investments in our network over time will be at an appropriate level.

We r~~R~~ecognise~~ing~~ that customer 'capital' contributions are a component of the overall recovery of our costs - in simple terms the level of contributions determines how much is recovered up front as opposed to on an ongoing basis. ~~– we will incorporate our approach to contributions into our set of pricing documentation.~~

In determining customer groupings, cost allocation and the structure of our pricing we:

- apply price averaging over large numbers of connections, because it is generally not practicable to single out individual connections for cost-reflective delivery pricing. Where it is practicable to do so we allocate assets and costs to the specific connection categories that use them,
- recognise that all consumers should share in the benefits of greater utilisation of shared assets and economies of scale,
- recognise that consumers generally change their demand behaviour over relatively long periods of time and it is important that we provide compelling and consistent pricing incentives aimed at maximising the efficient utilisation of our assets,
- use capital contributions to reflect costs associated with different density areas (particularly urban vs rural) as these charges apply at the time customers are making decisions about where to connect,
- seek to make our prices effective, by balancing strong price signals with simple application and measurement,

[4] Pursuant to section 2.4.4 of the information disclosure determination (IDD), and further to the discussion in section 3.3 below.

- set prices that are the same for all retailers, providing a "level playing field" to promote retail competition.

Key considerations relating to our pricing over the next five years include:

- our developing thinking on sustainability and the way we manage the trade-offs between the environmental and affordability aspects of the energy trilemma in New Zealand's transition to a low carbon economy,
- preserving incentives for managed water heating load,
- the impact of changing use of the network due to emerging technologies such as distributed generation, battery storage and electric vehicles,
- ~~the Commerce Commission's approach to the 1 April 2020 DPP reset and in particular the form of control as we move from a weighted average price cap to a revenue cap,~~
- our expectation that the government will move to phase out the low fixed charge regulations (which will remove a significant restraint on how we structure our prices),~~the recommendations of the government's Electricity Price Review, in particular its recommendations regarding the low fixed charge regulations,~~
- the Electricity Authority's initiatives in relation to its pricing principles and associated practice note and scorecards,
- changes to the transmission pricing methodology which we expect we will need to reflect in our pricing from April 2023.
- ~~continuing review of Transpower's transmission pricing methodology (TPM),~~
- ~~recent review of the pricing principles and associated practice note and scorecards.~~

The way we implement our pricing strategy is updated and publicly disclosed in our pricing methodology document. We usually change our delivery prices on 1 April each year. We review and update this pricing strategy at least annually.

In terms of the impact on individual connection categories, the expected changes to the low fixed charge regulations are likely to lead to a lowering of volume based pricing principally for residential connections, but affecting the wider general connection category, streetlighting and irrigation categories as well. Changes to transmission pricing will be reflected with a shift toward fixed pricing for all categories.

Expected longer term future trends in our pricing (beyond the one-year focus of this document) are set out in section 3.3.

The inclusion of the capital contribution approach within the strategy is not a change in itself. It is more a broadening of the strategy to recognise the overall approach to pricing, including prices (or costs) that apply at the point customers connect.

3 Overview of our methodology

3.1 Methodology

Our charges represent the delivery costs of electricity – we contract with Transpower to deliver electricity across the national grid from generation points to our network, and we provide the local network to distribute electricity to each connection.[5]

We refer to Transpower's service as *transmission,* our service as *distribution*, and the combined transmission and distribution service as a *delivery* service. We set delivery prices to recover the costs of the combined transmission and distribution service.

In summary, our pricing approach is to:

- establish connection categories based on connections that have similar load characteristics, use specific sets of assets or otherwise give rise to a similar set of costs
- establish total costs that drive our revenue requirement, including:
    - transmission charges and costs of investments that avoid transmission charges,
    - regulated recoveries and incentive allowances,
    - regulated pass-through cost allowances,
    - asset depreciation, asset disposal losses and return on capital invested, tax,
    - operations and maintenance costs,
    - administration costs,
    - payments to distributed generators in lieu of distribution costs,
    - payments to irrigators for power factor correction and interruptibility,
    - the extent to which costs are offset by other (non-delivery) revenue, such as advertising and car parking revenue, and
    - the revenue allowance imposed by the regulated default price path
- allocate transmission costs to each connection category based on our assessment of each category's use of the transmission system
- allocate regulated allowances to each connection category
- allocate non-asset based distribution costs (distributed generation and administration costs) to each connection category
- assess each connection category's use of network assets and assign the average depreciated value of assets to each connection category
- allocate asset related costs (operations and maintenance, depreciation and return on capital) to each connection category based on the asset value assigned to each category, and the applicable WACC as established by the Commission's Input Methodologies

[5] And, to an increasing extent, we deliver electricity produced at customer connections.

- calculate an overall adjustment that is required to meet the requirements of the Commission's price-quality path and allocate the discount to each connection category on an equitable basis (and if necessary, using the allocation to limit any price shock that might otherwise occur), and establish a revenue requirement for each category
- estimate the long run average incremental cost (LRAIC) of investment in our network
- establish a cost reflective pricing structure driven by LRAIC and estimate the chargeable quantities to establish the proportion of revenue that will be met with the cost reflective components
- for the balance of the revenue requirement (the "residual"), establish pricing structures which, within other considerations and limitations on pricing, minimise the extent to which the prices distort customer usage behaviour.

For the majority of our connections, we apply a 'GXP billing' approach where, in simple terms, charges are based on electricity volumes measured at the few points of injection into the Orion network (principally Transpower grid exit points). Chargeable quantities attributed to each retailer are determined by the wholesale electricity market reconciliation process with adjustments for embedded networks and major customer quantities. This provides a number of administrative efficiencies which are reflected in our costs.

The use of reconciled quantities also allows us to measure retailer's demands on the network half-hourly, which enables us to have cost-reflective 'peak' components in our pricing. Peak demands are measured over the periods when total network demand is high. We signal these periods to customers in real time to support customer choice.

For the majority of customers, alongside the peak component we apply a traditional volume (kWh) based component. This recovers a large proportion of our non-load dependent or residual costs, effectively allocating these costs between customers in proportion to energy usage. In the past this has provided an equitable and non-distortionary way of recovering these costs, but we are now observing responses to avoid volume based pricing which are not intended, and the responses are not matched by a reduction in our costs.

In addition to charges based on these reconciled quantities we have a 15 cents per day fixed charge for all general connections. We introduced this charge in April 2019 as an initial step to reduce volume based pricing and the distortionary responses noted above.

Retailers choose how they present our price signals to customers, and they do so in a variety of ways. Retailers can also manage their costs by leveraging features of the reconciliation process such as profiles and the use of individual customer's half hourly data from smart meters. Finally, retailers can use their understanding of different customer demand characteristics when modelling our costs. Our pricing supports innovation by leaving decisions about the relative importance of these factors, and how they might be responded to, to the competitive market.

More detail on how we apply our prices, and in particular on how the chargeable quantities are calculated for each connection category, can be found in our *Pricing policy* document, which is available on our website.

3.2 Factors influencing price movements

This year, the high level factors influencing our price changes are as follows:

Cost component	Comment	Impact on price / revenue
Transmission interconnection charges	Our share of the core grid charges varies from year to year as electrical loadings vary. This charge includes a 1.3% loading increase, offset by a 0.3% interconnection price reduction.	0.2% 0.6m
Transmission connection charges	Transpower's charges for assets at grid exit points are increasing an average of 9.2%, and Transpower has identified the cyclical nature of maintenance as well as higher depreciation from asset renewal for this increase. These charges are a relatively small component of overall costs, so the impact is diluted.	0.2% 0.3m
Transmission new investment agreement charges	We pay off the capital cost of new investments that Transpower undertake for us over a period of time, and we are reaching the end of one of these payment schedules during the year. The majority of this particular payment schedule (and therefore the reduction) is assigned to a customer in the large connection category.	(0.3%) ($0.7m)
Avoided transmission incentive	The DPP provides incentives where we take on costs that would otherwise contribute to transmission charges. One of these incentives ends on 31 March 2021, and the transmission savings are passed on to customers via a reduction in price.	(1.2%) ($2.8m)
Administration, Operations & Maintenance expenses	Each year we review and update our expense budgets to reflect underlying cost changes and the work planned for the year. Within this movement, our administration costs are increasing 20% due to a focus on improvements to our IT systems, increased customer engagement, increased insurance premiums and a continued focus on our future network. Offsetting this, operating costs are down 12% reflecting continued cost rationalisation. Maintenance costs remain at a similar level to the prior year.	0.9% $2.1m
Depreciation	This has increased in line with our asset renewal and replacement programme and has increase 0.9% this year.	0.9% $2.0m
Regulatory incentives and adjustments	The DPP includes incentives relating to expenditure and reliability, and includes adjustments for variations.	0.3% $0.7m
Other	Other minor cost changes (including changes in other regulated revenue which offsets the amount we can collect in delivery charges)	0.1% $0.1m
Return on capital, tax	Return on capital is set for the 5-year regulatory period under the DPP and includes an inflation adjustment each year. This component also absorbs the impact for the extent to which other factors and cost allowances vary from those set out in the DPP 5-year reset (that is, actual costs are higher than allowed for in the DPP, and our return on capital must reduce to remain under the price path).	(1.2%) ($2.7m)
Change in quantity forecasts	When chargeable quantities increase we must set lower prices to remain within the revenue limit set under the default price path (and vice versa).	(1.0%)
Total price movement		**(1.1%)**

The impact that these factors have on individual price movements varies as a result of the cost allocation process described in section 3.1 above.

3.3 Pricing trends

This pricing methodology is primarily focussed on the year ahead – April 2021 to March 2022. This section[6] comments on anticipated trends in pricing beyond this period, over the next five years – the primary driver is the regulated price path set by the Commerce Commission.

As noted above, Orion is subject to the Default Price-Quality Path (DPP), and at the current point, Orion is not intending to apply for an alternative customised price path. The DPP includes an allowable return on investment (referred to as a weighted average cost of capital, or WACC), as well as allowances for depreciation, operating expenditure, performance incentives and pass-through costs.

The DPP applies for 5 years from 1 April 2020, and following that we expect it will be reset for a further 5 years.

In terms of pricing impacts, complying with the DPP requires/includes:

- an initial price reduction which was applied on 1 April 2020, largely driven by the prevailing low interest rates included in the updated WACC,
- CPI linked price changes for each of the following 4 years, which we expect will equate to increases of around 2% per annum,
- an allowance to pass on changes in Transpower's charges. Transpower has advised an overall revenue requirement that remains quite stable, but the current demand based allocation method is volatile, and could result in overall price increases and reductions of around 4% from year to year. Transpower is also preparing a new pricing methodology under the Electricity Authority's revised guidelines which is set to take effect from 1 April 2023. It is not yet clear what impact this will have for transmission charges.
- allowances to pass on changes in rates and levies, which equate to a further 2% of our total revenue from pricing, and we expect will increase by up to 5% per annum,
- a quality incentive applicable from 1 April 2022 which we expect will increase or decrease overall pricing by up to 0.25%,
- a number of other incentives and allowances which will begin to affect our prices from 1 April 2025.

New and emerging technologies

Like most distributors, Orion is seeing an increase in the uptake of distributed generation. Orion is considering this in the wider context of emerging technologies and sustainability objectives.

In relation to this issue, Orion is of the view that the current low fixed charge regulations limit the opportunity to rebalance pricing to promote use of our network.

[6] This section is intended to provide the information specified in sections 2.4.4 (1), (2) and (3) of the Commission's information disclosure requirements. Section 2.7 includes the pricing strategy approved by the Orion board.

We note the recommendations in the Government's Electricity Price Review to address this limitation, and we understand that the Government is considering changes to phase out the restriction, beginning in April 2022. Prior to this change occurring it would be possible to establish separate pricing groups for higher usage residential connections and apply alternative pricing. However, we are concerned that this would enhance the inefficient response that we are looking to address, creating a fixed charge incentive for customers to avoid using and sharing renewable energy resources across our network.

Despite the current limitations imposed by the low fixed charge regulations, the Authority is advocating for pricing reform and has set out its expectations of distributors in implementing more cost-reflective and service-based pricing. This includes an expectation on us to publish and update a "road map" for reform and a "scorecard" assessment by the Authority to show the relative position of electricity distributors and to track progress. This is discussed more fully in Appendix C below.

4 Connection categories

We have identified situations where groups of customers place significantly different demands on delivery assets, and situations where customers use different sets of those delivery assets. One of the aims with establishing these consumer groups is to support pricing that is subsidy free, allowing prices to more accurately reflect contribution to costs to avoid exceeding stand-alone costs or over-recovery. We have established connection categories that reflect these differences to provide a more equitable basis of assigning costs. Our categories are:

- Streetlighting connections
- General connections
- Irrigation connections
- Major customer connections
- Large capacity connections

We determine which category applies to each ICP, and this is reviewed from time to time.

This section describes each of these categories, the rationale for maintaining the category, and the key statistics for the category. The key statistics inform the cost allocations set out in section 6.

4.1 Streetlighting connections

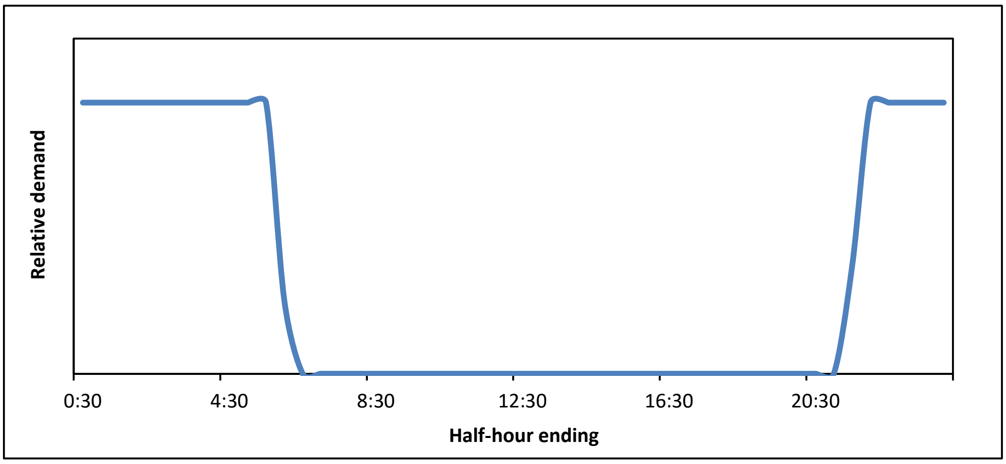
Orion owns and maintains a low voltage network of lines and cables dedicated to the provision of streetlighting (including lighting of some parks and reserves). To a large extent, this network runs alongside our regular low voltage network; it is the fifth wire on our overhead lines and the fifth core in our underground cables. These circuits are switched on at night and off in the mornings, using a combination of light sensors and timers and our ripple signalling system.

To reflect the dedicated use of our lighting network, we maintain a specific category for streetlighting connections. All private and publicly owned dedicated lighting connections supplied from our streetlighting circuit are included within this connection category.[7]

Assessed key statistics for streetlighting connections (1 April 2021 to 31 March 2022)	**Forecast**
Number of chargeable connections	51,113 (average)
Number of ICPs	490 (average)
Energy volume	19,549 MWh
Peak demands	
- contribution to network-wide winter peak (ADMD)	1,986 kW
- contribution to network-wide summer peak (ADMD)	0 kW
- contribution to local network peak (ADMD)	1,986 kW
- sum of individual connection anytime peaks (ΣAMD)	4,625 kW
Value of lost load (VOLL)	$15.38 / kWh

Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurements (i.e. with normal distribution losses added).

There is effectively no diversity of load within this category, and it contributes to both morning and evening load peaks during winter. A typical winter day profile:



[7] There is a small but increasing number of streetlights that are not connected to our dedicated streetlighting network and so are not in this category. These instead form part of our general connections category.

4.2 General connections

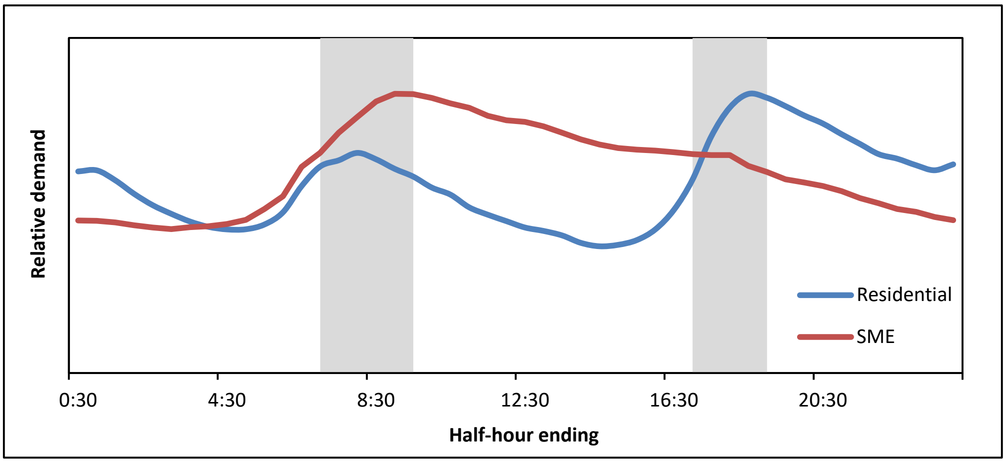
This category includes all residential connections and most business connections, including a number of sites with half-hour interval metering, but excludes connections that belong to the other connection categories (those in the streetlighting, irrigation, major customer and large capacity connection categories).

General connections make use of all network assets (except lighting circuits) and, given the cost reflectivity of our pricing within the category, we have not identified any significant reason to separately consider any subset of this category.

Assessed key statistics for general connections (1 April 2021 to 31 March 2022)	**Forecast**
Number of connections / ICPs	208,311 (average)
Energy volume	2,291,645 MWh
Peak demands	
- contribution to network-wide winter peak (ADMD)	472,402 kW
- contribution to network-wide summer peak (ADMD)	291,300 kW
- contribution to local network peak (ADMD)	472,402 kW
- sum of individual connection anytime peaks (ΣAMD)	1,999,000 kW
Value of lost load (VOLL)	$16.47 / kWh

Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurements (i.e. with normal distribution losses added).

The category includes a mix of customer types with different load profiles, and varying contribution to our winter weekday load peaks. The most dominant groups within the category are residential and small commercial, with the following typical winter weekday profiles:



4.3 Irrigation connections

We provide a specific irrigation connection category because electrical loads from irrigators are very different to those of other connection categories. In particular:

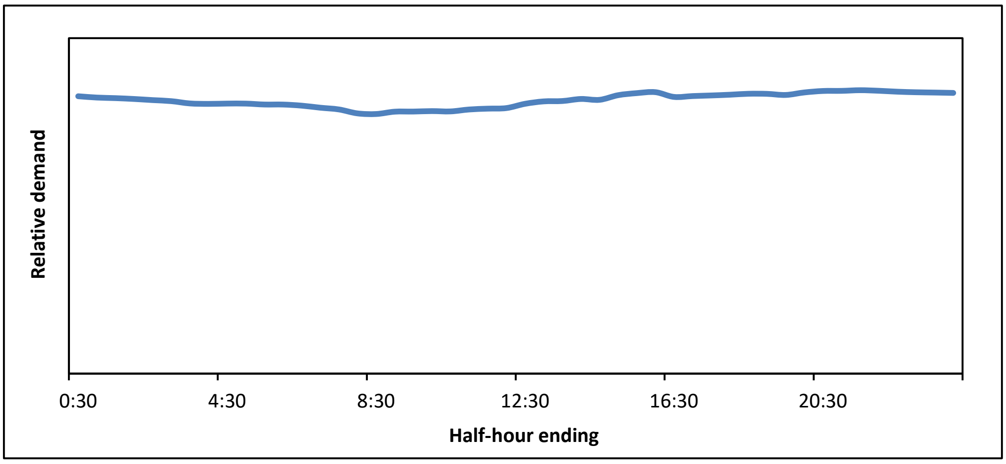
- they are all in lower density rural areas (using relatively long stretches of our overhead network),
- their load is highly correlated: when it's warm and dry they all switch on,
- their load and combined loading peaks are very flat (and any load management or demand response that aims to reduce these peaks must therefore operate for extended periods of time to be effective), and
- their peak demands occur in summer whereas the overall Orion network peak demands occur in winter.

This category generally applies to all connections with capacity greater than 20 kW where the primary purpose is to pump water to irrigate farmland. Orion determines the connections that are allocated to this category.

Assessed key statistics for irrigation connections (1 April 2021 to 31 March 2022)	**Forecast**
Number of connections / ICPs	1,040 (average)
Energy volume	133,700 MWh
Peak demands	
- contribution to network-wide winter peak (ADMD)	0 kW
- contribution to network-wide summer peak (ADMD)	34,552 kW
- contribution to local network peak (AMD)	56,847 kW
- sum of individual connection anytime peaks (ΣAMD)	78,438 kW
Value of lost load (VOLL)	$1.09 / kWh

Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurements (i.e. with normal distribution losses added).

The dominant irrigation load in the rural network area alters the shape of peak loads that drive a significant portion of our costs – the peaks are summer based, with a long flat duration. The category has the following typical daily load profile:



4.4 Major customer connections

We provide a specific category for our larger connections. These larger connections have enhanced metering that enables more specific and cost reflective pricing, and providing a separate category allows us to reflect specific factors for these customers, including:

- most have a dedicated transformer and generally do not use our low voltage network,
- in some cases, we do not own or maintain the transformer,
- some have additional dedicated equipment, lines or cabling, and
- some customers have specific additional requirements in terms of their security of supply and back-up supply options.

We determine which connections are in this category based on maximum loading levels (and any contracted capacity for new or modified connections). Generally:

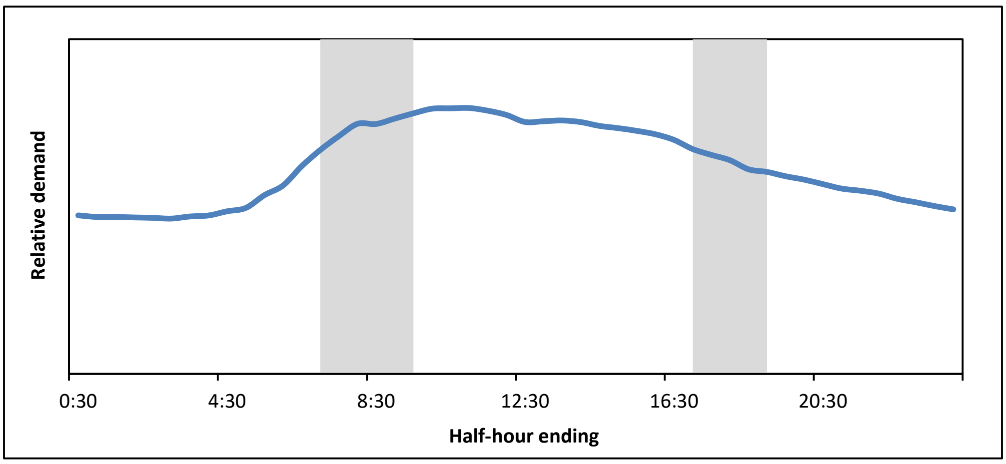
- where the loading or export level is between 150 kVA and 300 kVA the customer (or their retailer) may elect to be classified as a major customer connection, or
- where the loading or export level is above 300 kVA the connection is classified as a major customer connection.

However, irrigation connections and streetlighting connections are not categorised as major customer connections, and reconciled embedded networks are always classified as major customer connections.

Assessed key statistics for major customer connections (1 April 2021 to 31 March 2022)	**Forecast**
Number of connections / ICPs	503 (average)
Energy volume	864,779 MWh
Peak demands	
- contribution to network-wide winter peak (ADMD)	114,707 kW
- contribution to network-wide summer peak (ADMD)	134,687 kW
- contribution to local network peak (ADMD)	114,707 kW
- sum of individual connection anytime peaks (ΣAMD)	228,000 kW
Value of lost load (VOLL)	$23.00 / kWh

Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurements (i.e. with normal distribution losses added).

With a mix of commercial and industrial, the category is winter peaking (but much less seasonal than other categories) and has the following typical winter weekday profile:



4.5 Large capacity connections

We provide a specific pricing category to accommodate very large connections that require individual pricing consideration as a result of their size and impact on the local network. Such connections may also have:

- enhanced security of supply requirements, including back up supply and restoration obligations,
- very specific and dedicated assets, including transmission assets, and associated costs, with significant stranding risk should the connection cease operation,
- the ability to enter into long term contracts with us.

As a general guide, and subject to the considerations above, connections requiring a capacity of greater than 10 MVA in the urban area, or greater than 4 MVA in the rural area would be considered for large capacity pricing.

Pricing and charge structures are individually negotiated and charged directly to the customer. Because of this ability to negotiate very connection-specific pricing, we are in an even better position to ensure consistency with the pricing principles. Our contracts with these customers include terms that require us to allocate assets and asset related costs in a manner consistent with the overall pricing methodology including establishing and disclosing:

- assets and asset groups that are used in providing delivery services to the customer including assets provided in order to meet specific security of supply requirements,
- an equitable method for assigning a proportion of the value of assets to the customer for assets that are also used by other customers,
- the current replacement value of the asset allocation above,
- capital costs (return on assets and depreciation) based on the asset allocation above,
- an equitable method for assigning operations, maintenance and administration costs, which may include separate consideration of customer specific costs, asset specific costs, and shared costs,
- an allocation of transmission costs consistent with the overall pricing methodology, and
- a pricing structure that aims to recover allocated costs.

Assessed key statistics for large capacity connections (1 April 2021 to 31 March 2022)	**Forecast**
Number of connections / ICPs	15 (at 2 locations)
Number of customers	2
Energy volume	137,802 MWh
Peak demands	
- contribution to network-wide winter peak (ADMD)	6,470 kW
- contribution to network-wide summer peak (ADMD)	26,950 kW
- contribution to local network peak (ADMD)	26,950 kW
- sum of individual connection anytime peaks (ΣAMD)	31,904 kW
Value of lost load (VOLL)	$60.48 / kWh

Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurements (i.e. with normal distribution losses added).

Large capacity connections have specific non-standard contractual terms including delivery obligations and responsibilities in the event of supply interruptions. These attributes are disclosed in our *Disclosure of prescribed contracts* document which is available on our website. In general, for these customers we:

- provide uninterrupted supply security against a range of faults by maintaining duplicate supply assets,
- prioritise restoration of supply following outages, and
- maintain a “last to shed” priority for grid emergencies, and to the extent reasonably practical, not include the connections for “automatic under frequency load shedding”, nor “automatic under voltage load shedding”.

This supply security is greater than our standard undertakings which are set out in our “security of supply standard” in our published asset management plan. The key difference is that for a range of faults, power is off for the duration of the repair time (often up to 4 hours) under our normal security of supply standard. The higher supply security is provided for these customers through the provision of additional back up supply assets, and this is reflected in the prices applied.

With only two customers in the large capacity connection category commercial sensitivity prevents us from providing any load profile for this category.

5 Total costs and revenue requirement

Establishing a breakdown of our costs allows us to consider the drivers that influence these costs and establish a pricing basis that reflects different cost drivers.

The table below provides details of the delivery costs that we have forecast for the 2021 - 2022 year, which gives us our total target revenue:

Cost component (1 April 2021 to 31 March 2022)		**Forecast** $000		**Prior year forecast** $000
Transmission				
Transpower's interconnection charges		57,479		56,931
Transpower's connection and new investment charges		5,092		5,418
Avoided transmission costs		310		3,108
Transmission subtotal		**62,881**		**65,456**
Distribution				
Pass-through costs				
Local authority rates	4,297		4,213	
Commerce Commission levies	364		505	
Electricity Authority levies	651		616	
Utilities Disputes charges	120		113	
Pass-through cost subtotal		**5,432**		**5,447**
Regulatory incentive allowances		0		0
Payments to distributed generators in lieu of distribution costs		13		16
Capex wash-up adjustment		733		0
Fire and Emergency NZ (FENZ) levy		114		100
Payments for interruptible load and power factor correction		1,063		1,157
Administration costs		21,329		17,792
Operations and maintenance costs		45,764		47,201
Depreciation		46,000		44,000
Loss on disposals		960		940
Return on capital (after tax)		41,159		46,679
Taxation (regulatory tax including interest tax shield)		16,139		19,563
Less revenue received from avoided transmission charges		(310)		(3,108)
Less sundry revenue		(4,002)		(3,992)
Cost allocation reduction to meet DPP requirement		(8,440)		(11,908)
Distribution subtotal		**165,954**		**163,886**
Delivery total (total target revenue)		**228,835**		**229,343**

6 Allocating costs to connection categories

Each of the costs in the section above is individually considered and allocated to connection categories on a basis that reflects our pricing principles – in particular economic efficiency, equitability and practicality – and the key attributes of each category.

We allocate many of our distribution costs based on each category's use of our delivery assets, and to do this it is necessary to first allocate the assets to each category.

6.1 Distribution asset allocation

Our distribution asset allocation method takes account of a number of factors:

- assets are allocated based on our assessment of the relative use of each asset category by each connection category,
- the allocation of assets that are largely shared (e.g. sub-transmission assets) is weighted more in favour of each category's contribution to local peak demands (ADMD) on the basis that these assets are sized to meet the combined coincident loadings,
- the allocation of assets that are sized to meet the load of individual connections (for example low voltage assets), and those assets that tend to have a fixed size regardless of loading levels (for example land) is weighted more in favour of the sum of each individual connection's anytime peak (ΣAMD),
- the allocation of contingent assets (the assets that are provided to maintain supply after a fault - approximately 17% of our total asset value) is additionally weighted in proportion to each category's value of lost load (VOLL), as this measure reflects the relative need for the assets between the connection categories. We assess VOLL for each connection category as shown in section 4. The range of values we use is reasonably consistent with that from other sources[8] and ranges between $1 and $60 per kilowatt hour (much higher than the normal retail cost of delivered electricity which ranges from 12¢ to 30¢ per kilowatt hour).

We initially allocate assets based on the replacement cost and the detailed asset assessment contained in our latest audited regulatory valuation prepared in accordance with the Commission's optimised deprival value (ODV) methodology, prepared as at 31 March 2004.

[8] For example, the Authority in its 2013 paper "Investigation into the Value of Lost Load in New Zealand" estimated a range of $11 per kWh to $70 per kWh for a number of customer types in the Christchurch area. See: http://www.ea.govt.nz/dmsdocument/15385.

The resulting allocations by asset category are:

***Allocation of distribution assets** (based on 31 March 2004 ODV replacement costs)*

Asset category	Street lighting	General	Irrigation	Major customer	Large capacity*	Total
	$000	$000	$000	$000	$000	$000
Subtransmission	785	190,323	23,513	51,449	11,010	277,080
Power transformers	127	30,995	2,485	8,594	3,279	45,480
11kV Distribution	768	195,928	28,058	57,761	1,893	284,408
Land & property	163	70,584	2,585	8,278	2,444	84,054
Distribution transformers	224	84,674	4,326	8,868	80	98,172
Low voltage distribution	63	236,206	1,212	8,440	0	245,922
Lighting	14,577	0	0	0	0	14,577
Total	**16,706**	**808,710**	**62,180**	**143,389**	**18,705**	**1,049,691**

* New assets constructed for this category after the date of our ODV valuation are added in at their ODV-equivalent cost.

Notable entries in this table include:

- major customers are allocated a relatively small share (3%) of the low voltage distribution network assets when compared with their share of subtransmission (19%) and 11kV distribution assets (20%). This reflects their very limited use of LV assets,
- large capacity connections are allocated no LV asset costs,
- all of the lighting network asset costs are allocated to the streetlighting connection category.

We then allocate our forecast average regulatory asset value (average RIV) to each category in proportion to the allocation of replacement costs. We use this method to allocate RIV because it:

- captures the change in asset value between our valuation date and the pricing year,
- ensures that the same proportion of depreciation is applied to the assets assigned to all connection categories, reflecting that we provide an ongoing service, rather than a service with diminishing value (in other words a delivery service provided with older assets is no less valuable than a service provided with new assets),
- captures and assigns assets that are used for our delivery service, but are not included in our ODV (such as working capital, our faults vehicles and head office building).

The average RIV represents the indexed regulatory depreciated investment value of assets averaged over the year. The resulting allocation of average RIV for each connection category is:

	Street lighting	General	Irrigation	Major customer	Large capacity	Total
	$000	$000	$000	$000	$000	$000
Average RIV allocation	18,197	880,864	67,728	156,183	14,028	1,137,000

The full detail of the asset allocation calculations is not shown in this methodology as it is a complicated process involving many interacting components. However, by way of one example a diagram showing how the low voltage distribution assets are allocated to the general connection category is in Appendix D.

6.2 Other cost allocators

Costs that are not allocated on the basis of our asset allocation (above) are instead based on alternative allocators (i.e. in situations where the costs are not related to asset allocations). Summarising these allocators from section 4:

	Street lighting	General	Irrigation	Major customer	Large capacity	Total
	kW	kW	kW	kW	kW	kW
After diversity maximum demand (ADMD)						
During winter	1,986	472,402	0	114,707	6,470	595,565
During summer	0	291,300	34,552	134,687	26,950	487,489
During local network peak	1,986	472,402	56,847	114,707	26,950	672,892
Anytime maximum demand (AMD)	4,625	1,999,000	78,438	228,000	31,904	2,341,967

6.3 Transmission cost allocation

The investment in and capacity of the transmission system bringing electricity to our region is largely driven by the peak loadings within the greater upper South Island area. This is currently reflected in Transpower's interconnection charge (the main component of their charges to us) which is based on our contribution to Transpower's regional (in this case upper South Island) coincident peak demand (RCPD). This is split between winter peaks and (to a lesser extent) emerging summer peaks, and is measured over the top 100 half-hourly demands.

Our distribution network load is characterised by summer (rural) and winter (urban) seasonal peaks and, to the extent that all connection categories use the transmission service, and benefit from it, we have split the costs equally between the categories in proportion to their transmission demands (using network wide ADMD). We then allocate the additional cost of meeting the higher winter peak only to connection categories that contribute to the winter peak. This is not a 50:50 split. Based on current loading levels, the higher winter loadings mean that the winter peak attracts approximately a 50% greater share of the total interconnection charge.

This approach provides a smooth transition in the cost allocation as the observed summer peaks increase and approach the winter peaks. It also avoids the economic extremes of either:

- viewing the transmission grid as being built entirely for the winter peak (and allowing the lower summer peak to free-ride), or
- viewing the transmission grid as being built for the summer peak, and only charging the winter peaking customers for the marginal additional cost of meeting the higher peak.

Either of these approaches can be argued as economically efficient (and the Authority supports the former), but neither provides an equitable or stable result.

We allocate a proportion of Transpower's other charges (for connection assets and new investment agreements) to the large capacity category based on actual use of assets, and allocate the remainder of these charges to all other connection categories in proportion to each category's contribution to anytime maximum demand (ΣAMD).

Finally, we allocate the cost of transmission alternatives that we procure (currently just avoided transmission investments) according to ΣAMD as they are an alternative to connection assets.

The result of the allocation is:

	Street lighting $000	General $000	Irrigation $000	Major customer $000	Large capacity $000	Total $000
Transpower's interconnection charges	113	40,990	1,667	13,039	1,669	57,479
Transpower's connection and new investment charges	10	4,160	163	475	285	5,092
Avoided transmission investment	1	268	11	31	0	310
Transmission cost allocation	**123**	**45,418**	**1,841**	**13,544**	**1,954**	**62,881**

6.4 Pass-through cost allocation

The main component (nearly 80%) of pass-through costs is local authority rates, and these reflect the value of our assets. For simplicity we have allocated all pass-through costs in proportion to our allocation of assets. The resulting cost allocations are:

	Street lighting $000	General $000	Irrigation $000	Major customer $000	Large capacity $000	Total $000
Pass-through cost allocation	87	4,210	324	746	65	5,432

6.5 Incentives cost allocation

There are no regulatory incentives to apply in the pricing year.

6.6 Distributed generation distribution cost allocation

The distribution components of our export credits reflect the savings in distribution costs gained from this generation contribution. The cost reduction provided by distributed generators relates to their ability to lower our peak loading, and we allocate the cost of providing these credits based on each connection category's contribution to peak loadings (ADMD), with the following result:

	Street lighting $000	General $000	Irrigation $000	Major customer $000	Large capacity $000	Total $000
Distribution component of export credits	0	9	1	2	0	13

6.7 Capex wash-up adjustment cost allocation

The wash-up adjustment relates to capital expenditure, and we allocate these costs to connection categories in proportion to our allocation of assets. The resulting cost allocations are:

	Street lighting	General	Irrigation	Major customer	Large capacity	Total
	$000	$000	$000	$000	$000	$000
Pass-through cost allocation	12	575	44	102	0	733

6.8 FENZ levy cost allocation

For simplicity we have allocated the FENZ levy in proportion to our allocation of assets. The resulting cost allocations are:

	Street lighting	General	Irrigation	Major customer	Large capacity	Total
	$000	$000	$000	$000	$000	$000
FENZ levy cost allocation	2	88	7	16	2	114

6.9 Payments for interruptible load and power factor correction

Our irrigation rebate schemes allow us to avoid investment in capacity upgrades and back up supply assets. These schemes lower our overall cost of service to all customers in the area (not just the irrigation category). That is, we view the schemes as a network alternative, and we allocate the cost of this network alternative in the same way that we would allocate the cost of the network – they are funded by all categories. The power factor correction rebate works alongside the requirements in our network code, and encourage customers to provide a level of correction that goes beyond the normal technical requirement in the network code, and in this respect, we believe it provides a more useful incentive to maintain power factor correction than alternative approaches[9]. This explains why we do not allocate the cost of our irrigation rebate schemes just to irrigators. The allocation is carried out in proportion to our allocation of assets:

	Street lighting	General	Irrigation	Major customer	Large capacity	Total
	$000	$000	$000	$000	$000	$000
Payments for rebates	17	834	64	148	0	1,063

6.10 Administration cost allocation

Costs associated with administration and overheads are largely independent of asset value, so we instead allocate these costs to each connection category in proportion to the sum of individual connection anytime peaks (ΣAMD), as this reflects the extent to which each connection utilises our service. The resulting allocation is:

	Street lighting	General	Irrigation	Major customer	Large capacity	Total
	$000	$000	$000	$000	$000	$000
Administration cost allocation	42	18,235	716	2,080	256	21,329

[9] Alternatives include penalties for a low power factor, or charges for reactive load.

6.11 Operations and maintenance cost allocation

Operations and maintenance costs are asset related and we allocate these to each connection category in proportion to our allocation of assets.

	Street lighting $000	General $000	Irrigation $000	Major customer $000	Large capacity $000	Total $000
Operations and maintenance cost allocation	733	35,467	2,727	6,289	548	45,764

6.12 Cost of capital allocation (depreciation, return on capital and taxation)

Capital costs are all asset related, and we allocate these costs to connection categories in proportion to our allocation of assets. Offsetting these costs, we also provide a credit reflecting costs covered by avoided transmission charges, and a credit reflecting costs that are funded by sundry revenue (which is not collected via the prices in this methodology, eg rental income). The resulting cost allocations are:

	Street lighting $000	General $000	Irrigation $000	Major customer $000	Large capacity $000	Total $000
Depreciation	739	35,773	2,751	6,343	395	46,000
Loss on disposals	16	753	58	134	0	960
Return on capital	654	31,647	2,433	5,611	815	41,159
Taxation	258	12,483	960	2,213	225	16,139
Costs funded by avoided transmission	(1)	(268)	(11)	(31)	0	(310)
Costs funded by sundry revenue	(8)	(3,463)	(136)	(395)	0	(4,002)
Total cost of capital allocation	**1,658**	**76,924**	**6,055**	**13,875**	**1,434**	**99,946**

6.13 Target revenue adjustments and total cost allocation

The final step in establishing the total cost allocation for each connection category is to adjust (currently by way of a reduction) the allocation to meet the requirements of the default price-quality path.

When applying this reduction, we consider the impact of any changes in our cost allocation compared to previous years. From year to year, each category's contribution to our costs varies, as loadings and other factors change, and to provide some price stability we vary the discount to spread any significant changes in cost allocations over two to three years.

While the adjustments for transmission costs are shown separately, it is the combined transmission and distribution adjustments that represent the discount to our return on capital applied to each category.

Adding together each of the individual cost allocations (sections 6.3 to 6.12 above) gives our total target revenue for each connection category.

	Street lighting $000	General $000	Irrigation $000	Major customer $000	Large capacity $000	Total $000
Transmission costs allocation	123	45,418	1,841	13,544	1,954	62,881
Cost discount	0	0	0	0	0	0
Target transmission revenue	**123**	**45,418**	**1,841**	**13,544**	**1,954**	**62,881**
Pass-through costs	87	4,210	324	746	65	5,432
Regulatory incentives	0	0	0	0	0	0
Distributed generation cost allocation	0	9	1	2	0	13
Capex wash-up adjustment cost allocation	12	575	44	102	0	733
FENZ levy cost allocation	2	88	7	16	2	114
Payments for rebates	17	834	64	148	0	1,063
Administration cost allocation	42	18,235	716	2,080	256	21,329
Operations and maintenance cost allocation	733	35,467	2,727	6,289	548	45,764
Total cost of capital allocation	1,658	76,924	6,055	13,875	1,434	99,946
Cost discount	(137)	(6,620)	(509)	(1,174)	0	(8,440)
Target distribution revenue	**2,414**	**129,722**	**9,428**	**22,084**	**2,306**	**165,954**
Total target revenue	**2,537**	**175,140**	**11,270**	**35,628**	**4,260**	**228,835**
Proportion of total	**1.1%**	**76.5%**	**4.9%**	**15.6%**	**1.9%**	**100.0%**
Resulting return on capital	**2.9%**	**3.3%**	**3.1%**	**3.1%**	**5.8%**	**3.3%**

6.14 Comparison with prior target revenue

The following table shows a comparison with the target revenues from the prior pricing methodology. Changes often reflect a change in size or utilisation by a connection category and are therefore not proportional to changes in price (which are set out in the following section).

	Street lighting $000	General $000	Irrigation $000	Major customer $000	Large capacity $000	Total $000
Total target revenue (from above)	2,537	175,140	11,270	35,628	4,260	228,835
Prior year total target revenue	2,736	174,628	11,427	35,702	4,851	229,343
Increase (reduction)	(199)	513	(157)	(74)	(591)	(508)
Percentage increase (reduction)	(7.3%)	0.3%	(1.4%)	(0.2%)	(12.2%)	(0.2%)

7 Pricing structure and prices

We aim to structure our prices to provide cost reflective pricing signals to the users of our service. This promotes economic efficiencies in that customers can adjust their behaviour to reduce their delivery costs, and this change in behaviour provides a corresponding saving for us by avoiding or deferring investment.

We also aim to set prices that reflect differences in network services provided (for example, reflecting the costs of providing back-up assets), to allow customers to select alternatives where this is efficient, and to allow customers to make price/quality trade-offs where practicable. For our overheads and residual costs, we aim to set prices that least distort the way customers use our network.

The following sections:

- explain our determination of pricing structures for each connection category,
- provide our rationale for and forecast of chargeable quantities for each price component, and
- derive distribution and transmission parts of our delivery prices that provide the total target revenues established in section 6 above.

The final derived delivery prices are summarised in the schedules in Appendix A, *Delivery prices* and *Export credits.*

Customer funded assets

We receive capital contributions toward the construction of new assets and network extensions. These contributions are not treated as revenue from a regulatory perspective and, consistent with this, any assets vested to us enter our RIV at nil value, not at the cost of building them, while cash contributions are deducted from our capital expenditure in determining net additions to our RIV. This approach ensures that we do not make a return on assets that have been provided by others.[10]

7.1 Reflecting our long run average incremental costs (LRAIC)

A key aspect in establishing our pricing structure is to ensure that our prices are cost reflective. This supports appropriate decisions both by customers in using our network, and by Orion in investing in our network.

The most significant cost driver that influences our delivery service is the combined (coincident) peak demand of all customers (ADMD). We design and construct much of our network with the required capacity to meet this combined peak load. We consider that approximately 50% of our distribution costs are directly dependent on the coincident peak loading (the remainder of our costs are either fixed or dependent on the peak demand of individual customers or groups of customers).

To reflect this peak demand (ADMD) cost driver in our pricing, we have derived the long run average incremental cost (LRAIC) of delivery during peak loading periods and have reflected this in our pricing structure, as noted in the following sections. The LRAIC is the replacement

[10] See our *"Commercial terms for new connections and extensions"* document for a description of how we assess contributions. This document also states the contribution amounts for small and medium sized-connections. The document is available on our website: https://www.oriongroup.co.nz/assets/Company/Corporate-publications/CommercialTermsNewConnectionsExtensions.pdf

cost of the proportion of our distribution assets that is load dependent divided by the peak demand. Apart from minor differences due to the unit and point of measurement, the LRAIC is calculated on an equivalent basis for all relevant connection categories. See Appendix E for a summary of our calculation of the LRAIC, which we update each year.

Pricing with the LRAIC provides a long term indication of the typical cost of providing a distribution network solution to support demand. This can then be considered against alternatives such as different fuel sources and demand response. Using a long run pricing approach avoids the price volatility that would occur if a short run approach was taken to reflect localised constraints (because constrained areas change as network switching or upgrades occur to address the constraint). To a limited extent, responses to the price will often still assist with managing localised or short term peaks.

With load growth on an interconnected network, pricing with the LRAIC also sets a theoretical trading price where one customer can lower their contribution to peaks (and be rewarded at the LRAIC rate) and the capacity is then used by another customer (who pays at the LRAIC rate). This opportunity would not be available if the existing capacity was priced as a sunk cost (which is often the case with a forward looking short run marginal cost approach).

Where appropriate, the cost reflective LRAIC price is applied as a "peak price" and we signal to retailers and customers in real time when the price is being applied. This ensures that the price signal is "actionable" – that is, retailers and customers[11] have the opportunity to respond and be rewarded with lower charges.

For clarity, the LRAIC does not reflect the "replacement cost" of the network, it reflects all costs associated with providing assets that are needed to meet load at times of peak demand (including return on investment, depreciation, administration, operations and maintenance).

7.2 Locational pricing (urban vs rural)

Lower density rural areas require a greater degree of investment for each customer which provides a basis for applying a higher price. However:

- we continue to supply rural areas with lower cost overhead network solutions (whereas the vast majority of and all new urban networks are higher cost underground cable networks),
- rural customers make a greater contribution when first connecting to the network. This up-front funding is calculated to, on average, address the cost differential, and in our view, provides a clearer locational signal than would otherwise be the case with locational delivery charges,
- much of the existing rural and remote network was funded via the Rural Electrical Reticulation Council (RERC) which operated from 1946 to 1993 (rather than by our shareholders).

We are also conscious that rural customers receive a lower level of service, with a greater number of faults and longer restoration times.

[11] Where electricity retailers provide a corresponding retail pricing plan that reflects our peak price

Our pricing accounts for cost differences between urban and rural areas via differences in the up-front contributions that customers make. This occurs at the time that customers are making decisions about location of plant and premises, so the differential occurs at a time when the customer can be responsive.

As the differences have been accommodated via the initial funding, and noting the differences in service levels, we consider that there is no basis to further discriminate with higher locational pricing for our rural and remote network areas.

7.3 Streetlighting connections

Energy used by streetlighting connections is subject to our general connection prices applied to GXP reconciled volumes (including peak demands). While these prices are set in relation to the characteristics of the general connection category, we consider that they do provide adequate reflection of costs and incentives to maximise the efficiency of lights.

Lighting circuits are generally a standard size and are not constrained. We consider that a fixed daily charge per connection reasonably reflects the fixed costs associated with these circuits, which is used to recover the majority of the revenue requirement. This specific consideration of costs (and the revenue received from peak and volume prices) currently results in a lower fixed daily (per connection) charge than we apply under the general connection category.

The standard general pricing for transmission charges collects a little more than the transmission cost allocation, and this over-recovery is offset with a reduction to the fixed daily charge.

	Chargeable quantity	Distribution part	Transmission part	Distribution revenue $000	Transmission revenue $000
Fixed daily charge					
	51,113 connections	0.0985 $/connection/day	(0.0031) $/connection/day	1,838	(58)
Peak charge					
	1,881 kW	0.2419 $/kW/day	0.1576 $/kW/day	166	108
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)					
	2,526 MWh	0.05291 $/kWh	0.01464 $/kWh	134	37
Nights & weekends (Sat & Sun)					
	17,023 MWh	0.01627 $/kWh	0.00217 $/kWh	277	37
Total revenue				2,414	124
*compared with **target revenue** (from section 6.13)*				2,414	123

7.4 General connections

Our general connection category covers the vast majority of our connections ranging from small to large residential, and small to medium commercial connections.

As noted above we consider that a key cost driver in providing our delivery service is the coincident peak demand of all connections, and the cost of building our network to meet this, which is represented by the LRAIC defined above. Our updated calculations support an LRAIC of $82 per kW per year for general connections, which has reduced significantly from prior years with the inclusion of the updated WACC in 2020. Transitioning toward this lower level, our peak period demand price is set at $88 per kW per year (expressed as a daily price of $0.2419 per kW per day). With changes in WACC and changes in peak congestion loads, the calculated LRAIC assessment varies considerably from year to year. To provide a smooth price path and signal trends in the underlying cost assessments, we generally move the price to the calculated ideal price over a 2 to 3 year period whenever the movement is significant.

In addition, the winter based allocation of transmission interconnection charges is also recovered via the peak period demand price with a price of $58 per kW per year (expressed as a daily price of $0.1576 per kW per day).

The application of this peak price for general connections is described in our separate *Pricing policy* document. In short, chargeable peak demands are measured over the winter period May to August during the 100 or so hours when total network demand is highest. We signal these periods (using ripple signals, text and email) to support customer response. While estimates and wash-ups are required to apply the price, it cannot be characterised as a retrospective price. Customers know the price in advance, and we provide notification at the time it applies.

The rest of the revenue requirement is not related to usage or peak loading levels, and we aim to collect this revenue in an equitable way and minimise incentives that might distort behaviour. It is difficult to define "equitable" but broadly we are of the view that customers that use less of our service should pay proportionally less toward these costs.

The first part is met with the application of a 15 cents per connection per day fixed charge, which is the maximum universal amount that can be applied under the Low Fixed Charge regulations. At the lower end of the scale, a fixed daily charge is effective as it does not provide inefficient usage incentives.

The balance of our revenue requirement, including the balance of allocated transmission costs, are currently met with the application of traditional volume based pricing. The weekday price is set at a higher level to ensure that all subgroups within this category contribute equitably toward this cost (noting that some subgroups only contribute to volumes within this working weekday period). Also, the nights and weekend price is set at a lower level to avoid distorting the incentive provided by the peak price component (that is, it would be inefficient to discourage electricity usage at night).

Low power factor charge

A low power factor charge may apply in situations where a general connection has a power factor materially below 0.95 lagging. This charge allows Orion to encourage customers to improve their power factor so that we avoid having to carry out additional network reinforcement. We do not expect the charge to apply in many cases or to be a significant revenue item.

	Chargeable quantity	Distribution part	Transmission part	Distribution revenue $000	Transmission revenue $000
Fixed daily charge					
	208,311 connections	0.1500 $/connection/day	-	11,405	-
Peak charge					
	468,338 kW	0.2419 $/kW/day	0.1576 $/kW/day	41,351	26,941
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)					
	1,083,046 MWh	0.05291 $/kWh	0.01464 $/kWh	57,304	15,856
Nights & weekends (Sat & Sun)					
	1,208,599 MWh	0.01627 $/kWh	0.00217 $/kWh	19,664	2,623
Low power factor charge					
	0 kVAr	0.1500 $/kVAr/day	0.0500 $/kVAr/day	-	-
Total revenue				129,724	45,419
*compared with **target revenue** (from section 6.13)*				129,722	45,418

7.5 Irrigation connections

As noted in section 4 above, this category reflects irrigators' unique loadings and associated costs.

Energy used by irrigation connections is subject to our general connection volume prices applied to GXP reconciled volumes, and this provides a significant proportion of the revenue requirement for the category. Irrigators do not contribute to the GXP based peak charge set for general connections because they are not running during our peak periods that occur on the coldest winter days. Instead, we set a much lower demand charge based on the capacity rating of each irrigation pump motor to meet the balance of our revenue requirement for the category.

This price structure recognises that our delivery costs are primarily driven by the relatively constant load of pump motors (measured via their capacity rating), which show very little diversity during the irrigation season. In other words, we generally reach a point where all irrigators are on at the same time, and this behaviour sets the network peaks in the rural parts of our network. It also allows us to recognise this category's relatively small contribution to our winter-based transmission costs.

Power factor correction rebate (optional)

Most irrigation connections are eligible to apply for our power factor correction rebate. This rebate is provided to encourage more efficient use of our rural overhead network where improved power factor can avoid the need for network reinforcement.

We consider that it is most economical to correct power factors at the source of the problem, in this case the irrigation pump motor, and we set this rebate to ensure that customers receive a reasonable payback on their investment in power factor correction equipment.

Interruptibility rebate (optional)

Larger irrigation connections are eligible to apply for our interruptibility rebate. Using our interruptibility rebate arrangement, we contract with irrigators to be first to be cut off in a capacity emergency, and this allows us to provide a higher level of service to other customers with more critical loads.

The rebate arrangement provides a lower cost alternative method for us to meet our security of supply standards, and we set the price at a level that is sufficient to attract the required level of load reduction.

	Chargeable quantity	Distribution part	Transmission part	Distribution revenue $000	Transmission revenue $000
Capacity charges					
Chargeable pump capacity					
	76,469 kW	0.3762 $/kW/day	0.0621 $/kW/day	5,236	864
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)					
	55,064 MWh	0.05291 $/kWh	0.01464 $/kWh	2,913	806
Nights & weekends (Sat & Sun)					
	78,636 MWh	0.01627 $/kWh	0.00217 $/kWh	1,279	171
Rebates*					
Power factor correction					
	23,778 kVAr	(0.1618) $/kVAr/day	-	(not included – see section 6.9)	
Interruptibility					
	49,266 kW	(0.0405) $/kW/day	-	(not included – see section 6.9)	
Total revenue				9,429	1,841
*compared with **target revenue** (from section 6.13)*				9,428	1,841

* Rebates are not included in the total revenue because they are funded across all connection categories, as explained in section 6.9 above.

7.6 Major customer connections

A key cost driver in providing our delivery service is the coincident peak demand of all connections. The cost of reinforcing our network to meet this peak demand is reflected in our assessment of the long run average incremental cost – the LRAIC, as defined above. For major customer connections our updated assessment of the LRAIC (based on demands metered at the connection rather than the GXP) is $76 per kVA per year, which has reduced significantly from prior years with the inclusion of the updated WACC in 2020. We initially transitioned half-way to the reduced level, and this year we largely complete the transition, setting a price of $79 per kVA per year (expressed as a daily price of $0.2151 per kVA per day). With changes in WACC and changes in peak congestion loads, the calculated LRAIC assessment varies considerably from year to year. To provide a smooth price path and signal trends in the underlying cost assessments, we generally move to the calculated ideal price over a 2 to 3 year period whenever the movement is significant.

The winter based allocation of transmission interconnection charges is also recovered via the control period demand price with a price of $59 per kVA per year (expressed as a daily price of $0.1606 per kVA per day).

The application of this peak price for major customer connections is described in our separate *Pricing policy* document. In short, chargeable peak demands are measured over the winter period May to August during the 80 or so hours when total network demand is highest. We signal these periods (using ripple signals, text and email) to support customer response.

We also provide some dedicated equipment for major customer connections and the prices are included in the price schedule in Appendix A. We set our prices to cover all costs and reflect the more competitive nature of this aspect of our service.

The fixed costs associated with managing this pricing category and processing half-hour interval metering information, as well as a contribution toward the non-load related operational costs of the network is reflected in our fixed charges. Finally, we recover the balance of our distribution revenue requirement and the balance of the transmission cost allocation through the prices that are applied to customers' maximum demands.[12]

[12] See our separate *Pricing policy* document for the details on how demands are measured.

Chargeable quantity	Distribution part	Transmission part	Distribution revenue $000	Transmission revenue $000
Fixed daily charges				
Standard connections				
409 connections	10.0000 $/connection/day	-	1,493	-
Additional connections				
94 connections	5.0000 $/connection/day	-	172	-
Dedicated equipment charges				
Extra switches				
108 switches	3.3300 $/switch/day	-	131	-
11kV Metering equipment				
41 connections	4.3400 $/connection/day	-	65	-
11kV Underground cabling				
7.30 km	3.4000 $/km/day	-	9	-
11kV Overhead lines				
3.00 km	2.1400 $/km/day	-	2	-
Transformer capacity				
351,424 kVA	0.0119 $/kVA/day	-	1,526	-
Control period demand charges				
111,579 kVA	0.2151 $/kVA/day	0.1606 $/kVA/day	8,760	6,541
Capacity charges				
Nominated maximum demand				
276,387 kVA	0.0984 $/kVA/day	0.0050 $/kVA/day	9,927	504
Metered maximum demand				
231,578 kVA	-	0.0769 $/kVA/day	-	6,500
Total revenue			22,085	13,545
*compared with **target revenue** (from section 6.13)*			22,084	13,544

7.7 Large capacity connections

Orion provides a specific pricing category to accommodate very large connections that require individual pricing consideration as a result of their size and impact on the local network. We give specific consideration to the assets involved and the loading contributions which determine the network capacity required and any additional charges from Transpower.

Pricing and charge structures are negotiated directly with the customers. The table below compares projected revenue against target revenue.

	Chargeable quantity	Distribution part	Transmission part	Distribution revenue $000	Transmission revenue $000
Distribution charges (including amortisation of prepaid charges via development contribution)				2,306	-
Transmission charges				-	1,954
Total revenue				2,306	1,954
*compared with **target revenue** (from section 6.13)*				2,306	1,954

7.8 Revenue summary

The table below summarises the total projected revenue from the distribution and transmission parts of our pricing for each of the connection categories for 2021-22, and shows how this (and associated prices) have changed compared to the projection for the previous (2020-21) year. Changes in revenue are a product of both changes in price and changes in chargeable quantities, and these are also set out in the table:

	Street lighting	General	Irrigation	Major customer	Large capacity	Total
	$000	*$000*	*$000*	*$000*	*$000*	*$000*
Projected revenue 2021-22						
Distribution	2,414	129,724	9,429	22,085	2,306	165,958
Transmission	124	45,419	1,841	13,545	1,954	62,884
Delivery	**2,539**	**175,143**	**11,270**	**35,630**	**4,260**	**228,842**
Revenue change compared to previous year						
Distribution	(152)	2,439	58	(214)	(52)	2,079
Transmission	(45)	(1,917)	(214)	142	(539)	(2,573)
Delivery	**(198)**	**522**	**(156)**	**(72)**	**(591)**	**(494)**
Weighted average price change compared to previous year						
Distribution	(2.9%)	0.9%	1.2%	(3.3%)	(2.0%)	0.2%
Transmission	(2.8%)	(4.6%)	(9.7%)	(0.7%)	(20.0%)	(4.6%)
Delivery	**(2.9%)**	**(0.6%)**	**(0.8%)**	**(2.4%)**	**(11.6%)**	**(1.1%)**
Weighted average quantity change compared to previous year						
Distribution	(2.9%)	1.0%	(0.6%)	2.3%	0.3%	1.1%
Transmission	(25.9%)	0.7%	(0.7%)	1.9%	(1.5%)	0.7%
Delivery	**(4.3%)**	**0.9%**	**(0.6%)**	**2.2%**	**(0.7%)**	**1.0%**

Individual unit prices are set out against previous prices in a schedule in Appendix A, showing changes and percentage changes to each price. The factors driving these changes are set out in section 3.2 above.

8 Credits for export

Distributed generation that reliably generates during peak demand times can provide an economical alternative to electricity delivery and we provide export credits in recognition of this benefit to the network.

The credits do not represent the purchase of electricity, and exporting customers are able to separately negotiate to sell exported energy, usually to their electricity retailer.

Payments to generators are a cost incurred in providing our delivery service and, as with all other delivery costs, must be recovered from the customers that use our delivery service. The cost allocations in section 6.6 above show the assignment of these costs to connection categories.

We do not specifically charge customers for exporting electricity to our network, however, customers would be expected to fund any costs associated with situations where our network needed to be upgraded to accommodate the exported electricity. Separately, the nominated maximum demand charge for major customers, which broadly reflects the sizing of network delivery assets near the customer, is based on export demands where this is more than double the load demands, so excess peak export can increase delivery charges.

We do not maintain a separate category for customers with distributed generation. Customers in any category can install distributed generation, and our pricing approach is applied in addition to the pricing under the category.

Standard export credit prices

Export credits are based on the amount of electricity injected into our network during peak loading periods. The cost of delivery during peak loading is represented by our assessment of LRAIC which we calculate as $82 per kW per year (as noted in section 7.4 above).

Some of the costs represented in this LRAIC are not alleviated via export – for example, the required size for distribution transformers and low voltage systems is usually unchanged when generation is installed. Further, some network areas experience peaks that are not aligned with the timing of our signalled peak periods, and we reduce the standard credit price to reflect this divergence as well. Combining these factors, the distribution credit price is set at approximately a third of the full LRAIC.

We then separate the credit between real (kW) and reactive (kVAr) components of export, and we cap the amount of reactive export that is eligible for credits, to encourage appropriate levels of each.

Different categories are maintained to generally reflect the different metering information available from different sites, and standard credits are capped at 750kW of generation – above this level we individually consider the benefits to the network and apply specific pricing. We set a lower credit price for export that includes PV and where the metering arrangement only records total monthly export (referred to as “non-half-hour metering”) rather than the actual time that energy was exported. The lower price reflects average coincidence between export from PV generation and our network peak demands (usually occurring on cold winter days and evenings) that we observe at connections that do have the necessary metering for this assessment.

Exporting generators also reduce our exposure to Transpower's interconnection charges if they generate during Transpower's regional coincident peak demand periods. The Electricity Authority has revised the rules so that we are only able to reflect this savings in the credits applied to customers for generating connections that they approve, and at the date of this publication, no connections have been approved by the Electricity Authority.

The export credit prices and structure of pricing is shown in the "Export credit schedule" included in Appendix A.

Generation credit prices

We previously operated a generation credit arrangement to reduce loading levels via generation support at other times. As a result of reliability and administrative issues, we closed the scheme to new generation in 2017. With the approval restrictions for transmission savings noted above, we withdrew the credits effective 1 April 2019.

Appendix A - Price schedules

Electricity delivery price schedule for Orion NZ Ltd

(applicable from 1 April 2021)

This schedule lists the wholesale prices that Orion uses to charge electricity retailers and directly contracted customers for the electricity delivery service in Orion's network area. This delivery service includes the transmission and distribution of electricity to homes and businesses, but does not include the cost of the electricity itself. The separate transmission and distribution components of the total delivery price are shown in order to meet information disclosure requirements.

All prices exclude GST	Distribution	Transmission	Delivery Price (total)	Unit of measure
Streetlighting connections	*approx 51,113 connections*			
Fixed charge	0.0985	(0.0031)	**0.0954**	$/con/day
Peak charge (peak period demand)	0.2419	0.1576	**0.3995**	$/kW/day
Volume charge				
Weekdays (Mon to Fri, 7am to 9pm)	0.05291	0.01464	**0.06755**	$/kWh
Nights & weekends (Sat & Sun)	0.01627	0.00217	**0.01844**	$/kWh
General connections	*approx 208,311 connections*			
Fixed charge	0.1500	-	**0.1500**	$/con/day
Peak charge (peak period demand)	0.2419	0.1576	**0.3995**	$/kW/day
Volume charge				
Weekdays (Mon to Fri, 7am to 9pm)	0.05291	0.01464	**0.06755**	$/kWh
Nights & weekends (Sat & Sun)	0.01627	0.00217	**0.01844**	$/kWh
Low power factor charge	0.1500	0.0500	**0.2000**	$/kVAr/day
Irrigation connections	*approx 1,040 connections*			
Capacity charge	0.3762	0.0621	**0.4383**	$/kW/day*
Volume charge				
Weekdays (Mon to Fri, 7am to 9pm)	0.05291	0.01464	**0.06755**	$/kWh
Nights & weekends (Sat & Sun)	0.01627	0.00217	**0.01844**	$/kWh
Rebates				
Power factor correction rebate	(0.1618)	-	**(0.1618)**	$/kVAr/day*
Interruptibility rebate	(0.0405)	-	**(0.0405)**	$/kW/day*
* applied from 1 October to 31 March only				
Major customer and embedded network connections	*approx 503 connections*			
Fixed charge	10.0000	-	**10.0000**	$/con/day
Fixed charge (additional connections)	5.0000	-	**5.0000**	$/con/day
Extra switches	3.3300	-	**3.3300**	$/switch/day
11kV Metering equipment	4.3400	-	**4.3400**	$/con/day
11kV Underground cabling	3.4000	-	**3.4000**	$/km/day
11kV Overhead lines	2.1400	-	**2.1400**	$/km/day
Transformer capacity	0.0119	-	**0.0119**	$/kVA/day
Peak charge (control period demand)	0.2151	0.1606	**0.3757**	$/kVA/day
Nominated maximum demand	0.0984	0.0050	**0.1034**	$/kVA/day
Metered maximum demand	-	0.0769	**0.0769**	$/kVA/day
Large capacity connections	*15 connections*			
Individually assessed prices advised and charged directly to the customers				
Miscellaneous				
Monthly invoice and contract charge to retailers and directly contracted customers	30.00	-	**30.00**	$/invoice
Failure to pay notice	50.00	-	**50.00**	$/notice
Default and termination notice	100.00	-	**100.00**	$/notice

Notes

1. Full details on how we apply these prices are included in our *Pricing Policy* document, available on our website.
2. Peak and volume prices for streetlighting, general connections and irrigation connections are applied to peak loadings and volumes derived from measurements taken at grid exit points, and it is appropriate to allow for normal network losses when assessing the contribution individual connections make to these charges. All other prices in this schedule are applied against measurements or ratings taken at the connection.

Export credit schedule for Orion NZ Ltd

(applicable from 1 April 2021)

This schedule lists the credit prices that we use to credit electricity retailers or directly contracted customers for exports or contributions from their distributed generation. The credits do not represent the purchase of electricity. They are a recognition of the value to Orion in providing its delivery service. Credits are only available for generation approved by Orion and customers must apply in advance.

For exporting generators that were in place prior to 6 December 2016 and approved by the Electricity Authority an additional credit reflecting any actual savings in Transpower charges is available (at the date of issue of this schedule, no exporting generators have been approved by the Electricity Authority). In addition to applying for our distribution credit, exporting customers can approach Transpower (for example, under Transpower's demand response program) for recognition of any transmission benefit, and approach their electricity retailer for recognition of the value of energy exported.

Export credits are based on electricity exported only during specific time periods. Our prices for credits are:

(excluding GST)

Generator rated output	Period applied	Credit prices	Price Component Code[3]	Unit of measure
0 - 30kW generation[2]				
Anytime credits (without PV), or	Anytime	0.00290	EXPA	$/kWh
Anytime credits (with PV)	(24 hours, 7 days)	0.00010	EXPAPV	$/kWh
0 - 30kW generation[2]				
Peak period credits (with or without PV)	Chargeable peak period	0.20560	EXPPP	$/kWh
30 - 750kW Control period credits[4]				
- real power, plus	Chargeable control	0.0704	EXPCP1	$/kW/day
- reactive power[5]	period	0.0231	EXPCP2	$/kVAr/day
above 750kW	*Individually assessed prices provided on application*			

Notes for export credit pricing

1. Full details, including metering requirements and how credit prices are applied, are available in our *Export Credits Policy* document available on our website.
2. Small 0 to 30kW generators may elect (in advance) to receive the alternative peak period based credits, subject to the installation of appropriate metering to record peak period export.
3. The price component code is used in our mandatory 'electricity information exchange protocol' files.
4. Control period credits are assessed during control periods and applied as an annual credit at 365/366 times the daily credit price.
5. The credit quantity for reactive power (kVAr) export is limited to 33% of the credit quantity for real power (kW) export in each half hour period, the equivalent of exporting with a 0.95 lagging power factor.
6. Approximately 11 connections are approved for export credits.

Schedule of changes to electricity delivery prices

(applicable from 1 April 2021)

This schedule lists changes to the wholesale prices that Orion uses to charge electricity retailers and directly contracted customers for the electricity delivery service in Orion's network area. This delivery service includes the transmission and distribution of electricity to homes and businesses, but does not include the cost of the electricity itself.

Connection categories and price components	Units	Previous delivery price (1 April 2020 to 31 March 2021)	New delivery price (from 1 April 2021)	Change	Percentage change
Streetlighting connections					
Fixed charge	$/con/day	0.0997	0.0954	(0.0043)	(4.3%)
Peak charge (peak period demand)	$/kW/day	0.4120	0.3995	(0.0125)	(3.0%)
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)	$/kWh	0.06707	0.06755	0.00048	0.7%
Nights & weekends (Sat & Sun)	$/kWh	0.01798	0.01844	0.00046	2.6%
General connections					
Fixed charge	$/con/day	0.1500	0.1500	-	-
Peak charge (peak period demand)	$/kW/day	0.4120	0.3995	(0.0125)	(3.0%)
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)	$/kWh	0.06707	0.06755	0.00048	0.7%
Nights & weekends (Sat & Sun)	$/kWh	0.01798	0.01844	0.00046	2.6%
Low power factor charge	$/kVAr/day	0.2000	0.2000	-	-
Irrigation connections					
Capacity charge*	$/kW/day	0.4490	0.4383	(0.0107)	(2.4%)
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)	$/kWh	0.06707	0.06755	0.00048	0.7%
Nights & weekends (Sat & Sun)	$/kWh	0.01798	0.01844	0.00046	2.6%
Rebates					
Power factor correction rebate*	$/kVAr/day	(0.1658)	(0.1618)	(0.0040)	(2.4%)
Interruptibility rebate*	$/kW/day	(0.0415)	(0.0405)	(0.0010)	(2.4%)
* applied from 1 October to 31 March only					
Major customer and embedded network connections					
Fixed charge	$/con/day	10.0000	10.0000	-	-
Fixed charge (additional connections)	$/con/day	5.0000	5.0000	-	-
Extra switches	$/switch/day	3.2700	3.3300	0.0600	1.8%
11kV Metering equipment	$/con/day	4.2600	4.3400	0.0800	1.9%
11kV Underground cabling	$/km/day	3.3400	3.4000	0.0600	1.8%
11kV Overhead lines	$/km/day	2.1000	2.1400	0.0400	1.9%
Transformer capacity	$/kVA/day	0.0119	0.0119	-	-
Peak charge (control period demand)	$/kVA/day	0.3955	0.3757	(0.0198)	(5.0%)
Nominated maximum demand	$/kVA/day	0.1044	0.1034	(0.0010)	(1.0%)
Metered maximum demand	$/kVA/day	0.0762	0.0769	0.0007	0.9%
Miscellaneous					
Monthly invoice and contract charge to retailers and directly contracted major customers	$/invoice	30.00	30.00	-	-
Failure to pay notice	$/notice	50.00	50.00	-	-
Default and termination notice	$/notice	100.00	100.00	-	-
Export credits					
0 - 30kW generation					
Anytime credits (without PV), *or*	$/kWh	(0.0030)	(0.0029)	(0.0001)	(3.3%)
Anytime credits (with PV), *or*	$/kWh	(0.0001)	(0.0001)	-	-
Peak period credits (with or without PV)	$/kWh	(0.2107)	(0.2056)	(0.0051)	(2.4%)
30 - 750kW Control period credits	$/kW/day	(0.0721)	(0.0704)	(0.0017)	(2.4%)
plus	$/kVAr/day	(0.0237)	(0.0231)	(0.0006)	(2.5%)

Appendix B - Regulatory requirements: pricing principles and information disclosure

This appendix outlines and comments on the aspects of this methodology that relate to the regulatory requirements of the Electricity Authority's (the "Authority") pricing principles and the Commerce Commission's (the "Commission") information disclosure requirements.

In 2019 the Authority published the distribution pricing principles to set clear expectations for efficient distribution prices. The Authority considers that efficient distribution pricing is for the long-term benefit of consumers and that efficient distribution pricing will provide signals that help households and businesses to consume the right amount of electricity, at the right time, and in the right place.

Shortly after publishing the distribution pricing principles, the Authority published a "Practice Note" to help distributors interpret and apply the distribution pricing principles, and has also introduced a "scorecard" to evaluate distributors' pricing plans against the Authority's Distribution Pricing Principles.

The information disclosure requirements require us to prepare and disclose a statement of the level of alignment with the Authority's pricing principles, and this is set out below.

At the point of preparing this document for prices applying from 1 April 2021, we have not yet received the Electricity Authority's final published scorecard in respect of the prior pricing methodology and our review of its alignment with the pricing principles, and we are unable to take account of any issues or suggestions that might be made.

Electricity Authority pricing principles

The following are the published Authority principles[13] and, below each, a comment on our alignment:

"(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);

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

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

(iv) encouraging efficient network alternatives."

In line with these principles, we price to reflect the economic costs of providing our delivery service. We estimate the long run average incremental cost (LRAIC) of investment in our network (see Appendix E for more detail) and we set a peak load based price which reflects this. We consider that the peak load based incremental cost of our current network provides a suitable surrogate for the incremental cost of meeting future load growth, in the long term. The fact that we must apply other additional price components (over and above the component that reflects the LRAIC) shows that our prices are greater than avoidable costs (meeting the first "subsidy free" requirement in principle (a)(i)). Equally, prices are demonstrably lower than stand-alone costs on the basis that we provide a shared delivery service sized to meet the diversified load of customers, which is much smaller than the sum of individual load peaks. For example, we observe an average residential customer peak of 7.4 kW, but when looking at an entire residential suburb, the network peak equates to just 2.3 kW per household. An alternative approach to the assessment of stand-alone costs is also set out in the paragraphs below.

The Authority's Practice Note sets out an alternative basis for the subsidy free test. It focuses on consumer groups (or connection categories) rather than individual consumers. It also identifies avoidable cost as the costs that would reduce if a consumer group was not supplied with electricity, and the standalone costs as energy alternatives that would supply groups of consumers (such as micro-grids).

[13] As published in June 2019: https://www.ea.govt.nz/dmsdocument/25179-decision-paper-more-efficient-distribution-network-pricing-principles-and-practice-pdf

In this context we have estimated the boundaries for each connection category as follows

Connection category	Avoidable cost	($000)	Forecast revenue ($000)	Standalone cost	($000)
Streetlighting	Assuming that the separate lighting network assets could be abandoned			Reflecting geographic spread of load, an individual PV/Battery basis is assumed for each light	
	Repair and maintenance costs	686		Estimated cost per kWh*	$0.68
	Customer service, billing, and administration	341		Annual volume (MWh)	19,549
	Transmission interconnection	139			
		1,166	**2,539**	Total cost	**13,293**
General connections	Assuming that the majority of the low voltage network assets could be abandoned			Based on subdivision sized micro-grid estimate of shared PV and battery	
	Repair and maintenance costs	15,100			
	Customer service, billing, and administration	16,491		Estimated cost per kWh*	$0.48
	Transmission interconnection	42,681		Annual volume (MWh)	2,291,645
		74,272	**175,143**	Total cost	**1,099,990**
Irrigation connections	Assuming that distribution transformers and associated LV network assets can be abandoned			Reflecting geographic spread of load, an individual PV/Battery basis is assumed for each installation	
	Repair and maintenance costs	261			
	Customer service, billing, and administration	1,268		Estimated cost per kWh*	$0.68
	Transmission interconnection	-		Annual volume (MWh)	133,700
		1,529	**10,206**	Total cost	**90,916**
Major customer connections	Assuming that distribution transformers and associated LV network assets can be abandoned			Based on industrial subdivision sized micro-grid estimate of shared PV and battery, with supplimentary diesel generation	
	Repair and maintenance costs	814			
	Customer service, billing, and administration	2,924		Estimated cost per kWh*	$0.48
	Transmission interconnection	11,601		Annual volume (MWh)	864,779
		15,339	**35,630**	Total cost	**415,094**
Large capacity connections	Assuming that all dedicated asses can be abandoned			Based on large scale rurally located PV with battery storage	
	Repair and maintenance costs	211			
	Customer service, billing, and administration	381		Estimated cost per kWh*	$0.38
	Transmission interconnection	903		Annual volume (MWh)	137,802
		1,495	**4,086**	Total cost	**52,365**

* An estimate of the savings associated with avoiding purchasing energy at the wholesale rate of 12c/kWh has been deducted from this cost to provide a basis that is comparable with the delivery cost

The estimated costs per kWh used in the stand-alone cost assessments are broadly based on information taken from recent economic assessments. Actual costs of these alternatives will vary from location to location, but the magnitude of the stand-alone cost shows that the subsidy free test is not sensitive to inaccuracies in this metric. The forecast revenue is taken from section 7.8.

In all cases, the revenue we receive is greater than avoidable costs and less than standalone costs, demonstrating that our pricing meets the “subsidy free” requirement in principle (a)(i).

The LRAIC that we estimate is both a long-run and a network-wide value. This is not to suggest that the network is everywhere equally constrained or equally close to capacity limits in the shorter term. Rather, it reflects our intention to provide a long-term price signal against which customers (or retailers or third parties) can invest in demand-side alternatives wherever they are on the network. By maintaining this incentive over the entire network and the long-term we help ensure that the demand response will be consistent and so can be assumed in our network design and planning. In this way we believe we align with principle (a)(ii).

Peak pricing also ensures that customers that use more of our service contribute more to the cost of providing that service. The LRAIC based peak pricing approach provides a useful mechanism to share the cost of existing peak capacity driven investments, and inherently provides a basis to trade peak load contributions – that is, a reduction by one customer can be taken up by another, and the peak price provides a reward to the first customer funded by the second customer, which aligns with principle (a)(iii). This trading of network capacity between customers also inherently avoids capacity upgrades that would otherwise occur, and in this context the LRAIC based price aligns with principle (a)(ii), reflecting the impact on economic costs that would otherwise occur (including in areas where no capacity upgrades are planned).

Because the peak pricing reflects our assessment of LRAIC, any customer who reduces demand at peak times (be it by generation and / or load reduction) effectively reduces their costs by LRAIC. They are effectively electing to employ a network alternative where it is economic to do so. Since they will presumably only do this up to the point where it is at a cost lower than LRAIC, Orion will only build more network when customers have shown, collectively, that they are electing to use our service on the basis that it is available at lower cost than the alternatives (aligning with principle (a)(iv)). This is further explained in section 7.1 of the pricing methodology above.

Within our cost allocation we weight the allocation of assets that are installed for security of supply using the value that customers place on "lost load". This helps us reflect the different willingness to pay for these back-up assets between different connection categories. We also provide a specific rebate scheme for irrigation customers that elect to be first off following a capacity constraint caused by damage to or failure of our network.

We allocate Transpower's interconnection charges to each connection category based on our assessment of each category's use of the transmission system. Our distribution network load is characterised by summer (rural) and winter (urban) seasonal peaks. To the level of the lower summer peak, the transmission system is in place to meet both seasonal loads, and it would not be reasonable to view either winter or summer loads as "free" marginal additional loads. So, to the extent that all connection categories use the transmission service, we have split the costs equally between summer and winter peak demands. We then allocate the additional cost of meeting the higher winter peak only to connection categories that contribute to the winter peak. As a result, our price structure carries a lower winter demand price than Transpower applies to us, but provides a more equitable (in terms of cost sharing) and stable structure.

(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.

The LRAIC-based component of our pricing does not recover allowed revenue. We set fixed and volume prices for general connections, and maximum demand based prices for major customers, to collect the balance of our revenue requirement.

In relation to volume pricing:

- The low fixed charge regulations are a material constraint which leaves few options other than to apply volume based pricing to meet the revenue requirement,
- Our high volume price during weekdays is less avoidable than consumption during nights and weekends,

- Collecting revenue mainly against the day volume price ensures that all consumers within the category contribute equitably (noting that there are some sub-groups of consumers that naturally have very little usage outside of these times),

- Applying a lower night and weekend price avoids creating a disincentive for customers that elect to respond to our peak pricing signals by shifting load away from peak times.

Our capacity charge for major customers is based on the customer's own peak, which is less subject to demand response than other measures.

(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.

Orion may recognise an alternative opportunity available to a major customer in close proximity to a grid exit point and may reduce the chargeable demands to approximate the lower than average cost to distribute over the shorter distance.

We also individually negotiate the pricing and charge structure directly with large capacity customers. These connections have a significant impact on the network to which they connect such that significant additional investment by Orion is required. Customers that elect to go ahead with the supply will do so on the basis that the service provides economic value.

Customers in our major customer price category have the option to provide a range of their own connection equipment (transformers, switchgear, metering interfaces). Customers that elect to use our service will do so on the basis that they provide economic value in comparison with the alternatives available. These factors align with principle (c)(i).

For major customer and large capacity connections, we also provide the opportunity to tailor the quality of the service to the specific needs of the customer. Major customers can elect to use additional connections and/or additional connection equipment which can provide enhanced security of supply. Services for large capacity connections are provided with specific security undertakings which are required by the customer in light of the costs associated with the services. These options align with principle (c)(ii).

As additional examples of our alignment with principle (c)(ii):

- General customers have options to select from a range of water heating options, each providing a different level of service, and coming at a different effective cost (based on varying contributions to our peak price, weekday volume price, and our night and weekend volume price).

- Irrigation customers can choose to allow Orion to turn off their pumps during system emergencies, and the lower service level is reflected in credits that we pay.

More generally, all customers are free to invest in ways of achieving a higher quality service than that provided by our network, and for example:

- a number of larger customers have on-site backup generation capacity to achieve higher reliability than that provided by our network, and

- other customers invest in relatively low cost UPS devices (uninterruptible power supplies) for their critical loads, such as computers and cash registers.

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

Orion openly discloses its pricing methodology and actively works to promote a stable and long term pricing basis, recognising the impact on customers and the impact on investment decisions they have made in response to our pricing. We also recognise that any material changes to pricing structure can impose costs (including transaction costs) on stakeholders, and in particular retailers. In relation to this:

i. our structure for major customers has been in place for more than 25 years while our general connection pricing structure is largely unchanged since its inception in 1999;

ii. any significant changes are widely consulted on, and only made where we consider they will improve economic outcomes;

iii. material cost allocation changes are spread over a number of years to ease the impact on customers;

iv. price changes are only enacted after stakeholder consultation; and

v. longer-term price indications are provided to customers and retailers.

In addition to this methodology document we publish a plain English network pricing guide. Our asset management plan sets out our longer term plans for the network and this includes indications of key cost drivers. We conduct twice-yearly major customer seminars at which pricing and other matters are discussed.

Orion applies 'GXP billing' for most connections where charges are based on electricity volumes injected into the Orion network (principally at Transpower grid exit points). The chargeable quantities for most connections therefore use the results of the wholesale market energy reconciliation process, which is itself governed by the Electricity Industry Participation Code. This provides administrative efficiencies and a very low transaction cost that is reflected in our charges. Orion has relatively few connection categories (and 99% of connections are "general" connections) and there are relatively few prices within each category.

In terms of uptake incentives, when prices reflect costs, customers are rewarded for their elections (such as loading levels, water heating options, election to participate in rebate schemes) at an appropriate level, and the uptake incentive is inherent in the prices.

Pricing development is primarily focussed on achieving efficient outcomes for the long-term benefit of customers, but where possible we reduce retailer transaction costs. In recent years we have introduced a range of changes to simplify the application of our pricing.

In 2009 we:

- moved from kVA to kW charging for general connection peak periods, removing the need for both Orion and retailers to carry out what can be time-consuming and error-prone calculations;
- introduced an irrigation connection category which removed the need for retailers to calculate an annual wash-up;

- reduced the number of pricing zones within our network from two to one and simplified the structure of our loss factors so that there were only 4 factors (previously 24);
- spread the recovery of our peak period charges over twelve months rather than six, which smoothed retailer cash flows.

In 2010 we:

- aligned the “working week day” period for general and major customers;
- aligned the general peak period and major control period seasons, which also allowed us to reduce the number of months that we must estimate general peak period demands;
- moved to use standard half-hour metering for major customers (removing the requirement for special control period metering).

In 2013 we:

- further simplified the structure of our loss factors so that, for the vast majority of connections, one of only two applies.

In 2016 we:

- removed the split between distribution and transmission prices to publish and apply just the total delivery price;
- removed the public holiday distinction;
- rationalised dedicated equipment pricing from 45 items to 5 items;
- for major customers, replaced our assessed capacity approach with a combination of nominated maximum demand and metered maximum demand.

In 2017 we:

- consistent with broader moves to standardisation, expressed all prices in dollars (had been a combination of dollars and cents).

Commerce Commission information disclosure requirements

This section describes in a tabular format how this methodology document addresses key elements of the Commission's information disclosure requirements. Some of this information is included in the body of this methodology document above.

The relevant sections of the determination are 2.4.1 to 2.4.5.

IDD Section	Description of how addressed in this document
2.4.1 (1)	See IDD 2.4.3 below.
2.4.1 (2)	See sections 3.2, 5, 6.14, 7, 7.8and Appendix A.
2.4.1 (3)	See sections 4.5 and 7.7 for non-standard contracts. See section 8 for distributed generation.
2.4.1 (4)	See section 2.6.
2.4.2	The methodology is publicly disclosed before the end of February each year for prices that apply from 1 April each year.
2.4.3 (1)	See sections 4 through 7.
2.4.3 (2)	See the first part of this Appendix B.
2.4.3 (3)	See section 5.
2.4.3 (4)	See section 5.
2.4.3 (5) (a) & (b)	See section 4.
2.4.3 (6)	See sections 3.2 and 7.8.
2.4.3 (7)	See section 6.
2.4.3 (8)	See section 7. This shows amounts rather than proportions.
2.4.4 (1) to (3)	See sections 2.7, 3.3 and Appendix C.
2.4.5 (1) (a) to (c)	See sections 4.5 and 7.7.
2.4.5 (2) (a) & (b)	See section 4.5.
2.4.5 (3) (a) & (b)	See sections 6.6, 8 and Appendix A.

Appendix C - Our pricing roadmap

This appendix expands on the discussion in our pricing strategy (section 2.7), the pricing trends and interaction with new technologies covered in section 3.3, the alignment with the Authority's pricing principles in Appendix B above, and sets out our plans for pricing reform.

Problem definition

An ongoing step in the path of pricing reform is defining the problem that we need to address. We are faced with a range of significant influences and issues that we have the opportunity to address through pricing reform, and we face a number of restrictions in what we can do (regulated restrictions as well as practical limitations).

To a large extent there are trade-offs between meeting the wishes of different stakeholders. In our view, a significant aspect of this stage is to rationalise these influences, working with stakeholders to moderate areas of divergence, and to prioritise the various outcomes. We are also working with the industry and aim to establish this problem definition in the wider context, and to shape solutions to reflect this.

The objective is to provide clarity around what we should aim to achieve with our pricing, and we believe this is an important step before we turn our attention to the options for structural changes to our pricing.

Our current and emerging views on pricing reform

There are a number of factors driving the need for change to electricity delivery pricing, and these factors are not all aligned.

Sustainability, and a move to a low carbon economy is an important factor for us. In addition to operating our business in a sustainable way (and as the Authority has identified), our pricing can enable an *efficient* transition to a low-emissions economy. We consider that we can go further – our pricing can facilitate decarbonisation in our community. Within the framework of efficient and non-distortionary pricing, our pricing can encourage electrification of our transport fleet, electrification of industrial process heat, and the development of renewable generation. The right pricing can encourage (rather than discourage) the use of our network to interconnect customers to use existing renewable energy resources and to share new renewable energy resources.

Customers, the party most affected by our charges, have a diverse range of needs. Most notably, we observe a desire for pricing that is affordable, equitable and fair, clear and transparent, stable and consistent, and a desire for service-based options to meet different needs. We are particularly aware of the impact that changes in pricing structure can have. Adjusting pricing structures to achieve some of the outcomes above and below can have a significant impact on the amount some customers pay when there has been no change in their use of electricity. Changes can also undermine decisions that customers have made about things like heating appliances (eg gas vs electric), alternative energy sources (eg photovoltaics and batteries), or electric vehicle decisions.

The **Electricity Authority**, via its pricing principles, scorecard, practice note and letters to distribution businesses is calling for urgent change because it sees distribution pricing as one of the core elements of an efficient transition to a low-emissions economy. While very strongly signalling the need for change, the Authority's advice is unclear on what that change should be. The Authority has suggested that we should be transitioning to some form of real time locational pricing that signals the short run marginal cost of congestion in specific areas and alongside this we should meet the balance of our revenue requirement with prices that do not distort customer behaviour. We continue to actively seek pricing structures that would feasibly meet these ideals.

The **Government**, via its low fixed charge regulations, prevents us from recovering revenue from anything other than high volume pricing for the majority of our customers. The regulations prevent anything more than a token fixed charge and also prevent stepped or tiered volume or capacity pricing. We have been working with industry to lobby for change, and we understand that progress is being made, but we are yet to see any detail on how this restriction might change, or how any change might be phased in over time. If and when this detail becomes available, we can then begin to adjust prices within the current structure to better meet the objectives, and we can begin to plan alternative pricing structures to further enhance the desired outcomes.

Electricity retailers are lobbying for simple and nationally standardised pricing. We continually receive adverse feedback on the complexity associated with the peak congestion charge components in our pricing, and we observe that another distribution business was forced to abandon its peak charging approach in response to intense public pressure. This factor appears to be diametrically opposed to the influence of the Electricity Authority. We will continue to engage with electricity retailers to broaden the context and seek to reflect wider objectives within their expectations for our pricing.

Transpower's charges to us are set to change, and will move to a fixed (unavoidable) basis, which we will need to reflect in our pricing. It is not yet clear if this will be a step change in 2023, or if it will be transitioned over a period of years. To reflect the change we will need to de-weight our peak congestion charge and apply higher fixed prices where we can, or higher volume prices where we cannot.

In light of the context provided above, our roadmap for pricing reform is:

2021 Establish our problem definition - continue to work with stakeholders (in particular, the Authority and electricity retailers) to rationalise and moderate expectations in areas of divergence.

Await the outcome of changes to the low fixed charge regulations and the detail of how this restriction might be phase out.

Develop alternative non-distortionary pricing components that will allow us to de-weight the current volume pricing (likely some combination of fixed, capacity and/or metered maximum demand charging).

2022 Possible first step in reducing volume pricing.

Develop alternatives to address issues with peak congestion charging (reduce complexity, consider a move to short run locational cost reflection rather than long run network average).

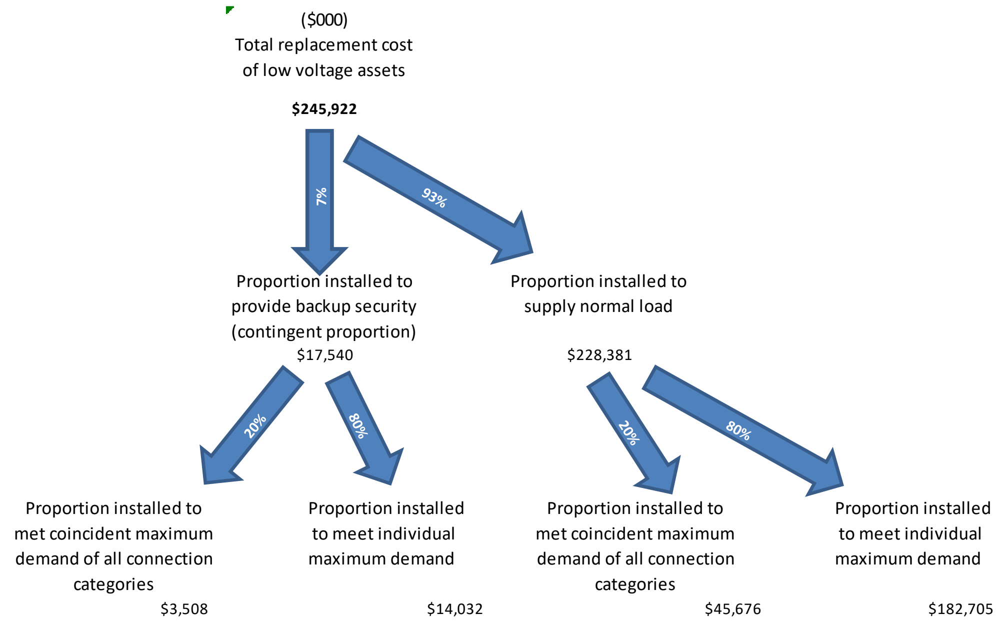
2023 Reduce peak congestion charge to reflect anticipated changes to Transpower's pricing structure (with a further increase in non-distortionary pricing).

Appendix D - Asset allocation example

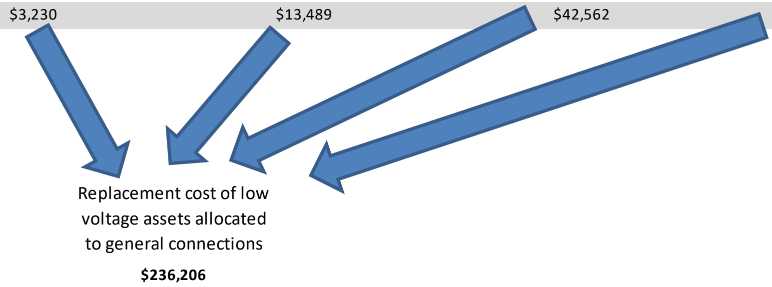
Example calculation

Asset allocation for low voltage assets to general connections

(based on replacement cost established in last regulatory ODV valuation)



Asset allocators applied				
Relative use of assets factor	1.00	1.00	1.00	1.00
VOLL	$16.47/kWh	$16.47/kWh		
AMD Loading		1,999,000 kW		1,999,000 kW
ADMD Loading	472,402 kW		472,402 kW	
Product of allocators (N)	7,780,332	32,922,983	472,402	1,999,000
Product of allocators across all connection categories (D)	8,449,265	34,249,889	506,962	2,064,306
Allocation proportion (N / D)	92.1%	96.1%	93.2%	96.8%
Allocated asset value	$3,230	$13,489	$42,562	$176,925



Appendix E - Derivation of LRAIC

Derivation of Long Run Average Incremental Cost

Orion derives its long run average incremental cost (LRAIC) for delivery of coincident peak load described in section 7.1 as follows:

Derivation steps

Step 1

Establish expected peak demand during the year

Upper HV network	627.3 MVA
Lower LV network	510.4 MVA

Step 2

Estimate the replacement cost of the network

Upper HV network	$1,141 m
Lower LV network	$461 m
Total replacement cost	$1,602 m

Step 3

Estimate the proportion of replacement cost that is load dependent

Upper HV network	$651 m
Lower LV network	$215 m
Total replacement cost	$866 m

Step 4

Estimate the proportion of the load dependent replacement cost that is sized for loadings coincident with network peaks

Upper HV network	$544 m
Lower LV network	$64 m
Total replacement cost	$608 m

Step 5

Calculate load dependent replacement cost per kVA

Upper HV network	$867 /kVA
Lower LV network	$125 /kVA
Total replacement cost	$992 /kVA

Step 6

Annualise the replacement costs and add in network average operations and maintenance

Upper HV network	$72 /kVA/year
Lower LV network	$10 /kVA/year
Total	$82 /kVA/year

See notes for each step on next page.

Notes

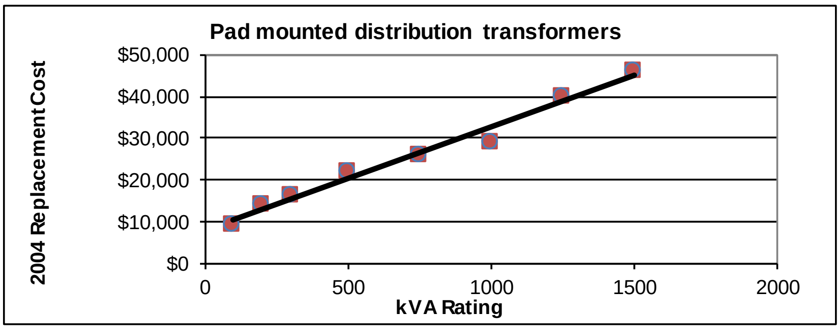
Step 1
This is the combined coincident peak demand of all loads

Step 2
Estimated as an average over the applicable pricing year

Upper network includes distribution transformers and above

Step 3

Individually assessed for each class of asset. For example, the cost of various size pad mounted distribution transformers shows that the fixed (load independent) cost is close to $8000 (the y-axis intercept in the graph below), and for our installed quantaties of these assets, this load independent cost equates to 48% of the total replacement cost



Step 4
This tends to be a considered engineering assessment. For example:

Asset	**Network peak load dependent proportion**	
Customer service fuses	Nil	While load dependent, these are sized to meet each customer's own peak load irrespective of the network peak load.
Low voltage conductors	35%	Based on the diversity between the sum of non-coincident peak demands of connections compared to that of distribution transformers.
11kV conductors	83%	Based on the diversity between the sum of non-coincident peak demands of distribution transformers compared to that of zone substations.
33kV and 66kV conductors	95%	Based on the diversity between the sum of non-coincident peak demands of zone substations compared to that of the total network.

Step 5
Simple division of load dependent replacement cost by the peak load delivered (both shown above)

Step 6
- Annualisation includes a levilised regulatory return, depreciation, taxation (including an allowance for the expected deprectaion tax shield), and asset based operation and maintenance costs.
- The upper HV network has an average total life of 52.3 years while the lower LV network has an average total life of 50.3 years.
- Budgeted operations and maintenance equates to 3.4% pa of RC for the upper HV network and 3.1% for the lower LV network.
- No allowance is made for administration cost on the basis that these are not asset or load dependent.

This annual cost is reflected in our peak pricing:
with adjustments for the basis of charging (ie loss factor and power factor adjustments),
smoothing the impact of changes (eg as a result of loading variablity) over a number of years, and
recognising the use of assets (in particular, major customers do not use the lower LV network)

Appendix F - Directors' certification of pricing methodology

In accordance with clause 2.9.1 of section 2.9 of the Commerce Commission's information disclosure determination for electricity distribution businesses the certification of Orion's pricing methodology document is included below.

We, Deborah Jane Taylor and Bruce Donald Gemmell, being directors of Orion New Zealand Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The attached information of Orion New Zealand Limited, prepared for the purposes of clauses 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.

Deborah Jane Taylor

Bruce Donald Gemmell

25 February 2021