Orion

Methodology for deriving delivery prices

For prices applying from 1 April 2020

Issued 24 February 2020

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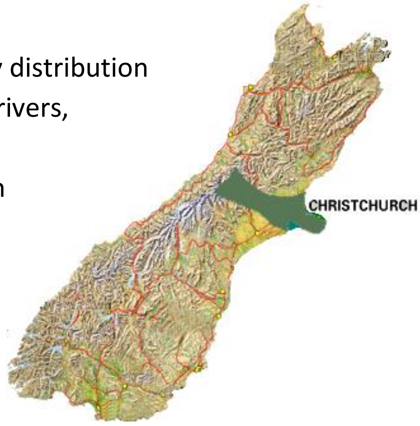
Glossary of abbreviations

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 200,000 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 36% 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: due to economies of scale a competitor could not profitably duplicate our network. 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 the Commerce Act 1986 (the Act). The Act is administered by the Commerce 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 ensuring that electricity distributors 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.

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

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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 our network is economically efficient. We apply this concept consistently in our pricing across the various groups, and in particular via the 'peak' components.

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 path). From 1 April 2020 Orion the Commerce Commission has "reset" the DPP to apply for a new 5 year regulatory period.

In relation to pricing, this reset 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.

Of particular note within the reset, the reduced WACC allowance is a significant factor in the price reductions that we are applying from 1 April 2020. Other than that, the detail of the price path is not included in this methodology, but we ensure that in our cost allocations we set the return on investment such 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 that use them,
- recognise that all customers should share in the benefits of greater utilisation of shared assets (and other enhanced economies of scale),
- 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 (for example, low night time prices that support off-peak usage),
- 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 Electricity Industry Act provision relating to the protection of rural customers which, as we interpret it, indicates that rural prices should not be different to urban prices[3],
- the Low Fixed Charge regulations that require that we provide pricing options with low fixed charges for residential customers, and
- the regulations relating to the connection of distributed generation.

[3] Electricity Industry Act 2010, section 113 (1) (c).

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. That is consistent with Orion's objectives.

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

This year we have introduced a sustainability consideration to our pricing strategy, which, initially, will influence our assessment of the trade-offs when we adjust different components of our pricing. We have 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.

Aside from these changes, we have updated our prices within the existing methodology framework.

2.6 Customer consultation

The information disclosure requirements set out in the October 2012 Commission determination 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.[4]

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 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.

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.

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

Specifically in terms of the price-quality trade off and reflecting this in price setting, for the most part we have *not* sought the views of customers, for the following reasons:

- in our view, consultation is relevant as part of the 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,
- further consultation as part of the price-setting process would involve considerable duplication of the AMP process, and
- the Commission consults on the framework of price-quality regulation on an ongoing basis. All consumers and their representatives have an opportunity to participate in that consultation.

2.7 Pricing strategy

Our high level pricing strategy was formally approved by the Orion board at its meeting on 10 December 2019. The strategy is as follows[5]:

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. We also aim to comply with the price control regulations.

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.

Recognising 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,

5 Pursuant to section 2.4.4 of the information disclosure determination (IDD), and further to the discussion in section 3.2 below.

- 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,
- seek to make our prices effective, by balancing strong price signals with simple application and measurement,
- 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,
- the recommendations of the government's Electricity Price Review, in particular its recommendations regarding the low fixed charge regulations,
- the Electricity Authority's:
    - 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.

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.[6]

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 give rise to a similar set of costs
- establish total costs, including:
  - transmission charges, costs of investments that avoid transmission charges and payments to embedded generators in lieu of 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, and
  - the extent to which costs are offset by other (non delivery) revenue, such as advertising and car parking revenue.
- 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
- calculate an overall discount 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 that minimises any resulting price shock

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

- 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 for the pricing structure
- using this price structure and quantities, set prices to meet the revenue requirement established by the cost allocation.

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 for Orion 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 we are managing load because 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 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 the 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 Pricing trends

This pricing methodology is primarily focussed on the year ahead – April 2020 to March 2021. This section[7] 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 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 from 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 (prices from 1 April 2020 include Transpower charges toward the higher end of the expected volatility). There is also a prospect of a change to the overall pricing methodology under which Transpower operates, and we anticipate that this could impact charges from 1 April 2024 at the earliest,

- 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 we do not expect will materially affect our pricing in the next 5 years.

New and emerging technologies

Like most distributors, Orion is seeing an increase in the uptake of photo-voltaic (PV) generation, mostly on houses. Orion is considering this in the wider context of emerging technologies (particularly including battery storage and electric vehicle charging) and sustainability objectives.

[7] 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.

In relation to this issue, Orion is of the view that the current low fixed charge regulations effectively limit the opportunity to rebalance where costs fall and the subsidies and incentives created within the residential customer segment. We note the recommendations in the government's Electricity Price Review to address this limitation, but we consider that the opportunity to make changes is several years away.

Regardless of this limitation, 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 "score card" assessment by the Authority to show the relative position of electricity distributors and track progress.   This is discussed more fully in appendix C below.

Changes to pricing strategy

This year we have adjusted our pricing strategy to:

- include sustainability considerations in the setting and structure of pricing, and
- include up-front connection contributions in the wider context of price setting.

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. We have established connection categories that reflect these differences to provide a more accurate 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

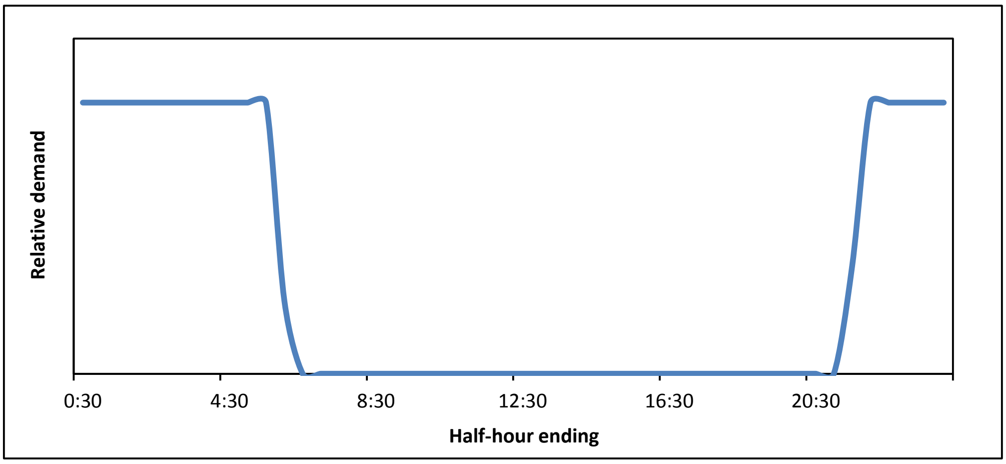
Orion owns and maintains a low voltage network of lines and cables dedicated to the provision of streetlighting (including lighting of some parks and reserves). To a large extent, this network runs alongside our regular low voltage network; it is the fifth wire on our overhead lines and the fifth core 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.[8]

Assessed key statistics for streetlighting connections (1 April 2020 to 31 March 2021)	**Forecast**
Number of chargeable connections	50,332 (average)
Number of ICPs	503 (average)
Energy volume	22,445 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	2,578 kW
– contribution to network-wide summer peak (ADMD)	145 kW
– contribution to local network peak (ADMD)	2,578 kW
– sum of individual connection anytime peaks (ΣAMD)	5,768 kW
Value of lost load (VOLL)	$15.33 / 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:



[8] 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

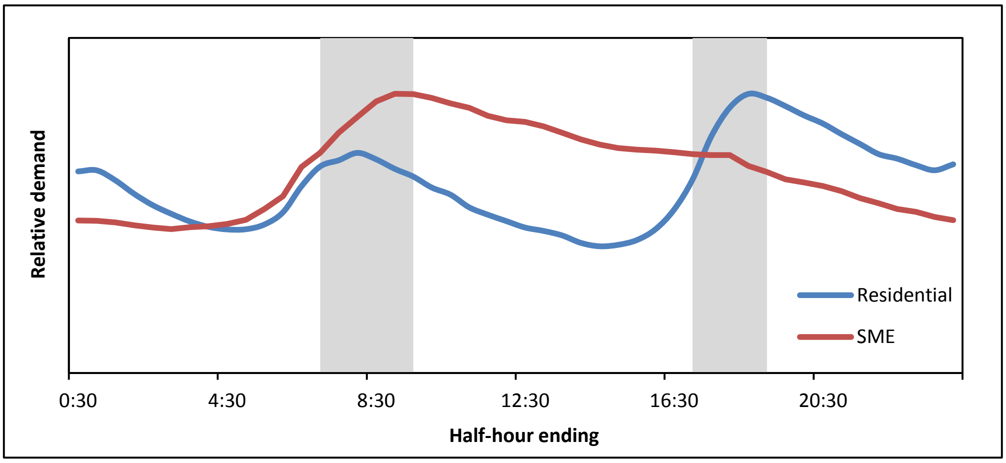
This category includes all residential connections and most business connections, including a number of sites with half-hour interval metering, but excludes connections that belong to the other connection categories (those in the streetlighting, irrigation, major customer and large capacity connection 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 2020 to 31 March 2021)	**Forecast**
Number of connections / ICPs	204,239 (average)
Energy volume	2,260,042 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	472,025 kW
– contribution to network-wide summer peak (ADMD)	306,303 kW
– contribution to local network peak (ADMD)	472,025 kW
– sum of individual connection anytime peaks (ΣAMD)	1,981,824 kW
Value of lost load (VOLL)	$16.00 / kWh

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

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:

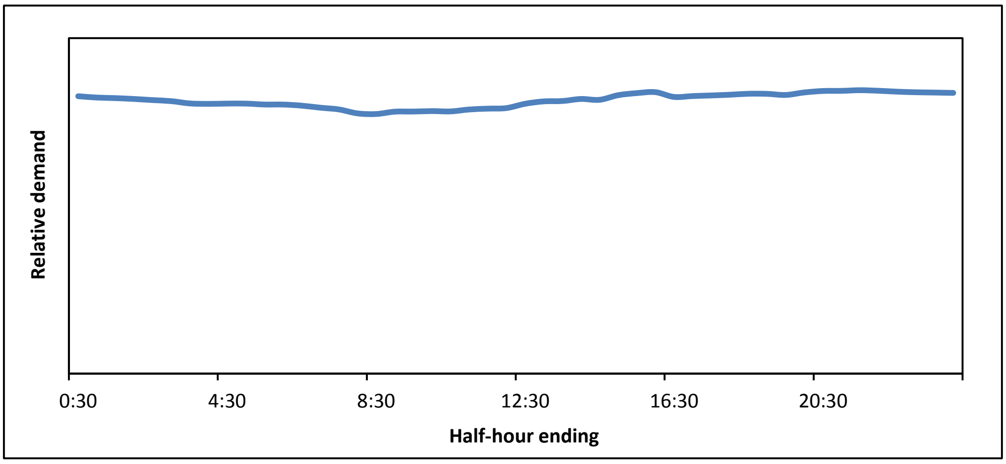
- they are all in lower density rural areas (using relatively long stretches of our overhead network),
- their load is highly correlated: when it's warm and dry they all switch on,
- their load and combined loading peaks are very flat (and any load management or demand response that aims to reduce these 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 2020 to 31 March 2021)	**Forecast**
Number of connections / ICPs	1,038 (average)
Energy volume	133,400 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	0 kW
– contribution to network-wide summer peak (ADMD)	36,516 kW
– contribution to local network peak (AMD)	53,691 kW
– sum of individual connection anytime peaks (ΣAMD)	95,332 kW
Value of lost load (VOLL)	$1.22 / 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:

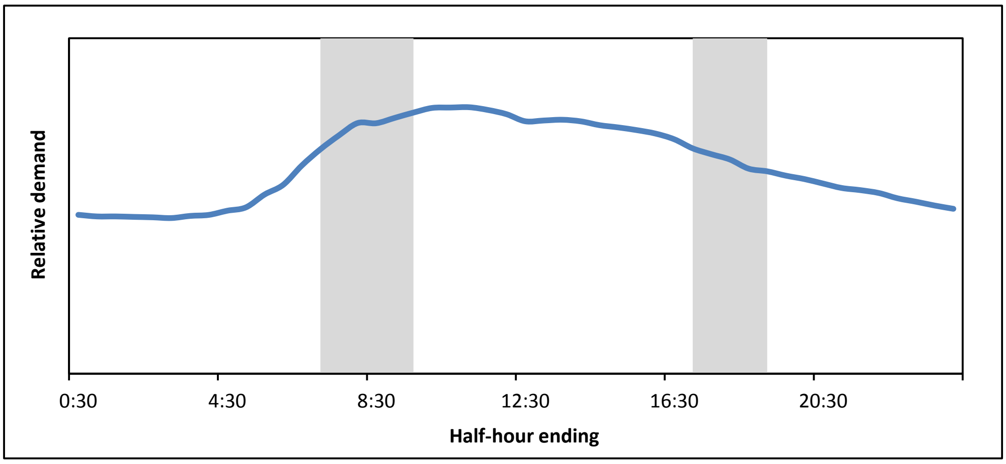
- where the loading or export level is between 150 kVA and 300 kVA the customer (or their retailer) may elect to be classified as a major customer connection, or
- where the loading or export level is above 300 kVA the connection is classified as a major customer connection.

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 2020 to 31 March 2021)	**Forecast**
Number of connections / ICPs	495 (average)
Energy volume	841,482 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	115,865 kW
– contribution to network-wide summer peak (ADMD)	131,054 kW
– contribution to local network peak (ADMD)	115,865 kW
– sum of individual connection anytime peaks (ΣAMD)	224,005 kW
Value of lost load (VOLL)	$22.93 / 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 2 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 2020 to 31 March 2021)	**Forecast**
Number of connections / ICPs	15 (at 2 locations)
Number of customers	2
Energy volume	140,665 MWh
Peak demands	
− contribution to network-wide winter peak (ADMD)	8,090 kW
− contribution to network-wide summer peak (ADMD)	25,970 kW
− contribution to local network peak (ADMD)	25,970 kW
− sum of individual connection anytime peaks (ΣAMD)	31,245 kW
Value of lost load (VOLL)	$60.29 / 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 taken account of and increases 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

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 2020 - 2021 year, which gives us our total target revenue:

Cost component (1 April 2020 to 31 March 2021)				**Forecast** \$000	**Prior year forecast** \$000
Transmission					
Transpower's interconnection charges				56,931	52,706
Transpower's connection and new investment charges				5,418	6,505
Avoided transmission costs				3,108	3,262
Transmission subtotal				**65,456**	**62,473**
Distribution					
Regulatory incentive allowances				0	4,034
Pass through costs					
Local authority rates		4,213	3,994		
Electricity Authority levies		616	600		
Commerce Commission levies		505	520		
Utilities Disputes charges		113	110		
Pass through cost subtotal				**5,447**	**5,224**
Payments to distributed generators in lieu of distribution costs				16	38
Administration costs				17,792	18,264
Operations and maintenance costs				47,201	47,820
Payments for interruptible load and power factor correction				1,157	1,192
Depreciation				44,000	43,000
Loss on disposals				940	2,000
Asset value (average regulatory asset base, \$000)[9]	1,103,514				
Applicable WACC	4.23%				
Return on capital (after tax)[10]				46,679	72,653
Less revenue received from avoided transmission charges				(3,108)	(3,262)
Less sundry revenue				(3,992)	(3,892)
Taxation				19,563	20,328
Cost allocation discount to meet DPP requirement				(11,808)	(24,902)
Distribution subtotal				**163,886**	**182,497**
Delivery total (total target revenue)				**229,343**	**244,970**

[9] This is our forecast average regulatory asset base (RIV) for the 2020 – 2021 year based on our disclosed RIV prepared in accordance with the Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2012.

[10] \$1,103,514k x 4.23% = \$46,679k.

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[11] 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.

[11] 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	1,026	190,160	22,351	52,409	10,072	276,017
Power transformers	166	30,875	2,354	8,750	2,899	45,044
11kV Distribution	1,000	195,624	26,974	58,620	1,651	283,870
Land & property	203	70,016	3,145	8,160	2,178	83,702
Distribution transformers	283	84,185	4,803	8,821	69	98,160
Low voltage distribution	80	236,062	1,342	8,437	0	245,922
Lighting	14,577	0	0	0	0	14,577
Total	**17,335**	**806,923**	**60,970**	**145,196**	**16,869**	**1,047,292**

* 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 (21%). 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	18,323	852,888	64,443	153,467	14,393	1,103,514

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 (ie, 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	2,578	472,025	0	115,865	8,090	598,558
During summer	145	306,303	36,516	131,054	25,970	499,988
During local network peak	2,578	472,025	53,691	115,865	25,970	670,129
Anytime maximum demand (AMD)	5,768	1,981,824	95,332	224,005	31,245	2,338,174

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 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 generally occurs in winter and is measured over the top 100 half hourly demands.

However, 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 approach provides a smooth transition in the cost allocation as the observed summer peaks increase and approach the winter peaks.

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	General	Irrigation	Major customer	Large capacity	Total
	$000	$000	$000	$000	$000	$000
Transpower's interconnection charges	150	40,711	1,737	12,650	1,683	56,931
Transpower's connection and new investment charges	12	3,959	190	447	810	5,418
Avoided transmission investment	8	2,670	128	302	0	3,108
Transmission cost allocation	**169**	**47,340**	**2,055**	**13,399**	**2,493**	**65,456**

6.4 Incentives cost allocation

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

6.5 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	General	Irrigation	Major customer	Large capacity	Total
	$000	$000	$000	$000	$000	$000
Pass through cost allocation	91	4,213	318	758	67	5,447

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	General	Irrigation	Major customer	Large capacity	Total
	$000	$000	$000	$000	$000	$000
Distribution component of export credits	0	11	1	3	0	16

6.7 Payments for interruptible load and power factor correction

Our irrigation rebate scheme allows us to avoid investment in capacity upgrades and back up supply assets. These schemes lower our overall cost of service and are funded by all categories, and we allocate the costs 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	19	906	68	163	0	1,157

6.8 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	44	15,096	726	1,706	220	17,792

6.9 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	General	Irrigation	Major customer	Large capacity	Total
	$000	$000	$000	$000	$000	$000
Operations and maintenance cost allocation	784	36,507	2,758	6,569	582	47,201

6.10 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	General	Irrigation	Major customer	Large capacity	Total
	$000	$000	$000	$000	$000	$000
Depreciation cost allocation	734	34,146	2,580	6,144	396	44,000
Loss on disposals	16	736	56	132	0	940
Applicable WACC (4.23%)	770	35,854	2,709	6,451	894	46,679
Taxation cost allocation	326	15,165	1,146	2,729	198	19,563
Costs funded by avoided transmission	(8)	(2,670)	(128)	(302)	0	(3,108)
Costs funded by sundry revenue	(10)	(3,429)	(165)	(388)	0	(3,992)
Total cost of capital allocation	**1,828**	**79,801**	**6,197**	**14,767**	**1,488**	**104,082**

6.11 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 discount) the allocation to meet the requirements of the default price-quality path.

When applying this discount, 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 6.10 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	169	47,340	2,055	13,399	2,493	65,456
Cost discount	0	0	0	0	0	0
Target transmission revenue	169	47,340	2,055	13,399	2,493	65,456
Regulatory incentives	0	0	0	0	0	0
Pass through costs	91	4,213	318	758	67	5,447
Distributed generation cost allocation	0	11	1	3	0	16
Payments for rebates	19	906	68	163	0	1,157
Administration cost allocation	44	15,096	726	1,706	220	17,792
Operations and maintenance cost allocation	784	36,507	2,758	6,569	582	47,201
Total cost of capital allocation	1,828	79,801	6,197	14,767	1,488	104,082
Cost discount	(199)	(9,247)	(699)	(1,664)	0	(11,808)
Target distribution revenue	**2,567**	**127,288**	**9,371**	**22,303**	**2,358**	**163,886**
Total target revenue	**2,736**	**174,628**	**11,427**	**35,702**	**4,851**	**229,343**
Resulting return on capital	**3.2%**	**3.8%**	**3.6%**	**3.6%**	**6.2%**	**3.8%**

6.12 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)	2,736	174,628	11,427	35,702	4,851	229,343
Prior year total target revenue	3,156	187,574	12,478	36,834	4,928	244,970
Increase (reduction)	(420)	(12,946)	(1,052)	(1,132)	(78)	(15,627)
Percentage increase (reduction)	(13.3%)	(6.9%)	(8.4%)	(3.1%)	(1.6%)	(6.4%)

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.

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 in us enter our RIV at the amount we pay, 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.[12]

[12] See our Connections and Extensions Policy 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: www.oriongroup.co.nz/ConnectionsAndExtensionsPolicy

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 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 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[13] have the opportunity to respond and be rewarded with lower charges.

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

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

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.

With these points we do not consider that it would be appropriate to apply 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, and they also cover the majority of the revenue requirement established for the category.

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 balance 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					
	50,332 connections	0.1039 $/connection/day	(0.0042) $/connection/day	1,909	(77)
Peak charge					
	2,382 kW	0.2580 $/kW/day	0.1540 $/kW/day	224	134
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)					
	2,909 MWh	0.05119 $/kWh	0.01588 $/kWh	149	46
Nights & weekends (Sat & Sun)					
	19,536 MWh	0.01456 $/kWh	0.00342 $/kWh	284	67
Total revenue				2,566	170
compared with **target revenue** (from section 6.11)				2,567	169

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 the LRAIC defined above. Our updated calculations support an LRAIC of $84 per kW per year for general connections, which has reduced significantly from prior years with the inclusion of the updated WACC. Transitioning toward this lower level, our peak period demand price is set at $94 per kW per year (expressed as a daily price of $0.2580 per kW per day).

In addition, the winter based allocation of transmission interconnection charges is also recovered via the peak period demand price with a price of $56 per kW per year (expressed as a daily price of $0.1540 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.

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.

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 User Fixed Charge regulations. 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 meet with the application of traditional volume based pricing. Recognising the different load profiles of customer groups within this connection category, and to ensure all customers contribute, we recover 76% though the application of weekday-based volume pricing, and 24% though the night and weekend based volume pricing, which has lower utilisation (particularly among some subgroups of consumers).

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					
	204,239 connections	0.1500 $/connection/day	-	11,182	-
Peak charge					
	467,672 kW	0.2580 $/kW/day	0.1540 $/kW/day	44,041	26,288
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)					
	1,068,955 MWh	0.05119 $/kWh	0.01588 $/kWh	54,720	16,975
Nights & weekends (Sat & Sun)					
	1,191,087 MWh	0.01456 $/kWh	0.00342 $/kWh	17,342	4,074
Low power factor charge					
	0 kVAr	0.1500 $/kVAr/day	0.0500 $/kVAr/day	-	-
Total revenue				127,285	47,336
compared with **target revenue** (from section 6.11)				127,288	47,340

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, rather than their diversified combined loading. 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					
	76,807 kW	0.3846 $/kW/day	0.0644 $/kW/day	5,376	900
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)					
	56,028 MWh	0.05119 $/kWh	0.01588 $/kWh	2,868	890
Nights & weekends (Sat & Sun)					
	77,372 MWh	0.01456 $/kWh	0.00342 $/kWh	1,127	265
Rebates*					
Power factor correction					
	25,587 kVAr	(0.1658) $/kVAr/day	-		
Interruptibility					
	50,998 kW	(0.0415) $/kW/day	-		
Total revenue				9,371	2,055
compared with **target revenue** (from section 6.11)				9,371	2,055

* Rebates are not included in the total revenue because they are funded across all connection categories

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 $77 per kVA per year, which has reduced significantly from prior years with the inclusion of the updated WACC. Transitioning toward this lower level our control period demand price is set above this level at $87 per kVA per year (expressed as a daily price of $0.2382 per kVA per day).

The winter based allocation of transmission interconnection charges is also recovered via the control period demand price with a price of $57 per kVA per year (expressed as a daily price of $0.1573 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.[14]

[14] 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				
402 connections	10.0000 $/connection/day	-	1,467	-
Additional connections				
93 connections	5.0000 $/connection/day	-	170	-
Dedicated equipment charges				
Extra switches				
104 switches	3.2700 $/switch/day	-	124	-
11kV Metering equipment				
42 connections	4.2600 $/connection/day	-	65	-
11kV Underground cabling				
7.30 km	3.3400 $/km/day	-	9	-
11kV Overhead lines				
3.00 km	2.1000 $/km/day	-	2	-
Transformer capacity				
333,432 kVA	0.0119 $/kVA/day	-	1,448	-
Control period demand charges				
111,736 kVA	0.2382 $/kVA/day	0.1573 $/kVA/day	9,715	6,415
Capacity charges				
Nominated maximum demand				
264,287 kVA	0.0964 $/kVA/day	0.0080 $/kVA/day	9,299	772
Metered maximum demand				
223,488 kVA	-	0.0762 $/kVA/day	-	6,216
Total revenue			22,300	13,403
compared with **target revenue** (from section 6.11)			22,303	13,399

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)			2,358	-
Transmission charges			-	2,493
Total revenue			2,358	2,493
*compared with **target revenue** (from section 6.11)*			2,358	2,493

7.8 Revenue summary

The table below summarises the total projected revenue from the transmission and distribution parts of our pricing for each of the connection categories for 2020-21, and shows how this (and associated prices) have changed compared to the projection for the previous (2019-20) 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 2020-21						
Distribution	2,566	127,285	9,371	22,300	2,358	163,879
Transmission	170	47,336	2,055	13,403	2,493	65,456
Delivery	**2,736**	**174,621**	**11,425**	**35,702**	**4,851**	**229,336**
Revenue change compared to previous year						
Distribution	(393)	(15,388)	(1,101)	(1,784)	57	(18,609)
Transmission	(25)	2,430	48	657	(135)	2,975
Delivery	**(419)**	**(12,958)**	**(1,052)**	**(1,127)**	**(78)**	**(15,634)**
Weighted average price change compared to previous year						
Distribution	(10.4%)	(10.5%)	(8.4%)	(9.2%)	4.8%	(10.0%)
Transmission	7.4%	6.4%	4.8%	4.5%	(0.7%)	5.6%
Delivery	**(9.3%)**	**(6.4%)**	**(6.3%)**	**(4.5%)**	**1.7%**	**(6.0%)**
Weighted average quantity change compared to previous year						
Distribution	(3.1%)	(0.4%)	(2.3%)	2.0%	(1.6%)	(0.2%)
Transmission	(18.8%)	(0.9%)	(2.3%)	0.7%	(4.2%)	(0.8%)
Delivery	**(4.1%)**	**(0.5%)**	**(2.3%)**	**1.5%**	**(3.0%)**	**(0.4%)**

The changes in revenues and prices reflect our estimates of the changes in total costs, the allocation of those to each connection category according to our cost allocation methodology, our projections of movements in chargeable quantities, our contractual commitments (in some cases) and the price regulation that we face.

In comparison with the previous year, the main impact on the overall distribution price movement is the revenue cap applied by the Commerce Commission under its DPP determination which, among other things, takes account of the current low interest environment in which we are operating, and lowers our target revenue and prices accordingly.

Separately, the main driver behind our transmission price increase is the amount Transpower charges us. While Transpower's pricing is lower this year, its assessment of our peak loads has increased, and this has increased the target revenue and prices.

In more detail, compared to previous prices, the main factors contributing to the overall delivery price movement in the table above are:

Cost driver	Impact on price
Transmission	
Interconnection charges	1.7%
Connection charges	(0.4%)
Avoided transmission incentive	(0.1%)
Distribution	
Return on capital	(5.3%)
Regulatory incentive reduction	(1.6%)
Admin / Ops / Maintenance expenses	(0.4%)
Depreciation	0.4%
Other	(0.7%)
Change in quantity forecasts*	0.4%
Total movement	**(6.0%)**

* When chargeable quantities increase we are able to set lower prices and still achieve the target revenue requirement (and vice versa).

Individual unit prices are set out against previous prices in a schedule in Appendix A, showing changes and percentage changes to each price.

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.

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 $84 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 64% below 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 were 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.

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 2020)

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. Please refer to your electricity retailer for details of retail electricity prices. 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 50,332 connections*			
Fixed charge	0.1039	(0.0042)	**0.0997**	$/con/day
Peak charge (peak period demand)	0.2580	0.1540	**0.4120**	$/kW/day
Volume charge				
Weekdays (Mon to Fri, 7am to 9pm)	0.05119	0.01588	**0.06707**	$/kWh
Nights & weekends (Sat & Sun)	0.01456	0.00342	**0.01798**	$/kWh
General connections	*approx 204,239 connections*			
Fixed charge	0.1500	-	**0.1500**	$/con/day
Peak charge (peak period demand)	0.2580	0.1540	**0.4120**	$/kW/day
Volume charge				
Weekdays (Mon to Fri, 7am to 9pm)	0.05119	0.01588	**0.06707**	$/kWh
Nights & weekends (Sat & Sun)	0.01456	0.00342	**0.01798**	$/kWh
Low power factor charge	0.1500	0.0500	**0.2000**	$/kVAr/day
Irrigation connections	*approx 1,038 connections*			
Capacity charge	0.3846	0.0644	**0.4490**	$/kW/day*
Volume charge				
Weekdays (Mon to Fri, 7am to 9pm)	0.05119	0.01588	**0.06707**	$/kWh
Nights & weekends (Sat & Sun)	0.01456	0.00342	**0.01798**	$/kWh
Rebates				
Power factor correction rebate	(0.1658)	-	**(0.1658)**	$/kVAr/day*
Interruptibility rebate	(0.0415)	-	**(0.0415)**	$/kW/day*
* applied from 1 October to 31 March only				
Major customer and embedded network connections	*approx 495 connections*			
Fixed charge	10.0000	-	**10.0000**	$/con/day
Fixed charge (additional connections)	5.0000	-	**5.0000**	$/con/day
Extra switches	3.2700	-	**3.2700**	$/switch/day
11kV Metering equipment	4.2600	-	**4.2600**	$/con/day
11kV Underground cabling	3.3400	-	**3.3400**	$/km/day
11kV Overhead lines	2.1000	-	**2.1000**	$/km/day
Transformer capacity	0.0119	-	**0.0119**	$/kVA/day
Peak charge (control period demand)	0.2382	0.1573	**0.3955**	$/kVA/day
Nominated maximum demand	0.0964	0.0080	**0.1044**	$/kVA/day
Metered maximum demand	-	0.0762	**0.0762**	$/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 2020)

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	0.00300	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	0.21070	EXPPP	$/kWh
30 - 750kW Control period credits[4]				
- real power, plus	Chargeable control period	0.0721	EXPCP1	$/kW/day
- reactive power[5]		0.0237	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 2020)

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 2019 to 31 March 2020)	New delivery price (from 1 April 2020)	Change	Percentage change
Streetlighting connections					
Fixed charge	$/con/day	0.1133	0.0997	(0.0136)	-12.0%
Peak charge (peak period demand)	$/kW/day	0.4292	0.4120	(0.0172)	-4.0%
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)	$/kWh	0.07559	0.06707	(0.00852)	-11.3%
Nights & weekends (Sat & Sun)	$/kWh	0.01798	0.01798	-	-
General connections					
Fixed charge	$/con/day	0.1500	0.1500	-	-
Peak charge (peak period demand)	$/kW/day	0.4292	0.4120	(0.0172)	-4.0%
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)	$/kWh	0.07559	0.06707	(0.00852)	-11.3%
Nights & weekends (Sat & Sun)	$/kWh	0.01798	0.01798	-	-
Low power factor charge	$/kVAr/day	0.2000	0.2000	-	-
Irrigation connections					
Capacity charge*	$/kW/day	0.4696	0.4490	(0.0206)	-4.4%
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)	$/kWh	0.07559	0.06707	(0.00852)	-11.3%
Nights & weekends (Sat & Sun)	$/kWh	0.01798	0.01798	-	-
Rebates					
Power factor correction rebate*	$/kVAr/day	(0.1755)	(0.1658)	(0.0097)	-5.5%
Interruptibility rebate*	$/kW/day	(0.0439)	(0.0415)	(0.0024)	-5.5%
* 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	NA	5.0000		
Extra switches	$/switch/day	3.6700	3.2700	(0.4000)	-10.9%
11kV Metering equipment	$/con/day	4.4500	4.2600	(0.1900)	-4.3%
11kV Underground cabling	$/km/day	3.2900	3.3400	0.0500	+1.5%
11kV Overhead lines	$/km/day	2.0700	2.1000	0.0300	+1.4%
Transformer capacity	$/kVA/day	0.0138	0.0119	(0.0019)	-13.8%
Peak charge (control period demand)	$/kVA/day	0.4148	0.3955	(0.0193)	-4.7%
Nominated maximum demand	$/kVA/day	0.1135	0.1044	(0.0091)	-8.0%
Metered maximum demand	$/kVA/day	0.0713	0.0762	0.0049	+6.9%
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	(0.0037)	(0.0030)	(0.0007)	-18.9%
Anytime credits (with PV), *or*	$/kWh	(0.0001)	(0.0001)	-	-
Peak period credits (with or without PV)	$/kWh	(0.2626)	(0.2107)	(0.0519)	-19.8%
30 - 750kW Control period credits	$/kW/day	(0.0897)	(0.0721)	(0.0176)	-19.6%
plus	$/kVAr/day	(0.0295)	(0.0237)	(0.0058)	-19.7%

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.

The then Electricity Commission published a set of pricing principles in February 2010, together with information disclosure guidelines. The principles-based approach to distribution pricing, as we interpret it, encourages all distributors to conduct their pricing in a similar way. The Authority inherited these principles and guidelines on its establishment in November 2010. It has recently revised the principles, replaced the guidelines with a practice note and introduced a 'scorecard' approach to assess distributor pricing and pricing development.

Together these documents require distributors to prepare and disclose a statement of the alignment of their pricing with the principles. The Authority will then review these disclosures.

Electricity Authority pricing principles

The following are the published Authority principles [15]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. 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 that the average residential customer peak of 7.4kW, but when looking at an entire residential suburb, the network peak equates to just 2.3kW per household. An alternative approach to the assessment of stand-alone costs is also set out in the paragraphs below.

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

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

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).

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)).

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 and stable structure.

With respect to principle (a)(i) as regards "subsidies", we note that the low fixed charge regulations mean that the proportion of our charges that apply to energy volumes is set higher to compensate, with the result that the savings that accrue to investment in technologies such as PV are inflated above the economic benefits achieved.

More generally, we have noted others' estimates of standalone costs. For example:

- An Australian provider of off-grid PV and battery solutions [16]

[16] See: https://www.solarpoweraustralia.com.au/remote-area-solar-power-for-your-home.

- Powerco has provided a reference to and used an MBIE [17] (MED at the time) commissioned publication[18] that shows a range of cost estimates for PV systems on a levelised cost of energy basis out to 2035.

These costs, once converted to a levelised cents per kWh basis, are comparable with the *retail* prices that customers pay, since a standalone customer avoids not just delivery, but energy and at least some other retail costs that come with grid connection. The following table shows how these standalone cost estimates compare with estimated retail costs for the main Orion connection categories. Note that we have:

- where options were available, chosen the "off-grid" scenario, which seems most appropriate for the standalone case,
- where costs were shown over time, used the values for the last year available, these being the lowest values.

Connection category	Estimated retail cost[19] (cents per kWh)	Standalone cost (cents per kWh)
Streetlighting	22.40	85-90
General	28.40	85-90
Major	14.40	85-90
Irrigation	19.60	85-90

Innovation may of course drive down the standalone cost over time.

(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. Our high volume price during the working weekday is less avoidable than consumption during nights and weekends.

The low fixed charge regulations are a material constraint in this area, but we consider that keeping our off-peak volume prices relatively low is more efficient than having a single flat rate at all times as it supports customer choices such as 'night-rate' water heating.

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:

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[17] In their *Electricity pricing methodology 2018,* pp49-50.

[18] *Assessment of the Future Costs and Performance of Solar Photovoltaic Technologies in New Zealand,* IT Power Australia, 2009. The website link is: https://www.mbie.govt.nz/dmsdocument/2826-assessment-of-the-future-costs-performance-of-solar-pdf. Table 8.1 on page 67 is the source of the numbers used here. These are 2008 $, but we have not tried to adjust them for either inflation of exchange rates. If anything, this understates them.

[19] For General connections we have used the MBIE QSDEP results for Christchurch for August 2018. For other categories we have added 10 cents per kWh as an estimate of the energy cost in addition to the variablised delivery cost.

(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 5, 7 and 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 sections 5, 6 and 7.
2.4.3 (4)	See section 5.
2.4.3 (5) (a) & (b)	See section 4.
2.4.3 (6)	See section 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, 3.2 and Appendix C.
2.4.5 (1) (a) to (c)	See section 4.5 and 7.7.
2.4.5 (2) (a) & (b)	See section 4.5.
2.4.5 (3) (a) & (b)	See section 8 and Appendix A.

Appendix C - Our pricing roadmap

This appendix expands on the discussion in sections 2.7, 3.2 and appendix B above and sets out Orion's current plans with respect to possible future pricing changes. This appendix also responds to the 'pricing scorecard' structure proposed by the Authority in August 2019.

Our current and emerging views on pricing reform

While it is too early to say what sort of changes we will make to our pricing, we are able to provide our current and emerging views.

As we see it, the Authority's principal concern with current distribution pricing is that it is too consumption (kWh) based. As discussed in appendix B above, a significant proportion (roughly half) of Orion's revenue comes from consumption based charges, although these are 'TOU', not flat rate. We have this charge structure for a number of reasons, but a key one is compliance with the low fixed charge (LFC) regulations.[20]

The Authority released guidance on how it will assess compliance with the regulations indicating that daily capacity charges would not be assessed as fixed charges. We do not agree with this interpretation and consider that all other stakeholders (particularly those exposed to the charges) would in fact see daily capacity charges as fixed charges. We remain concerned that implementing changes that the Authority deems compliant could be successfully challenged under the regulations, and the changes would then need to be reversed. We are of the view that the Authority's guidance has significantly delayed changes to address the issue.

The government's electricity price review has sought views on the regulations, and submissions have generally favoured their revocation. We acknowledge this would be a major step for the review to recommend and even more so for any government to implement. But without that clear support from the top, it is unreasonable to expect regulated parties to seek some sort of workaround. We appreciate that, if the regulations are revoked, some form of phase out will be required. We are happy to explore options with officials.

More generally though, there is some risk that a focus on capacity, even if accepted by customers, has undesirable side-effects, such as:

- Customers may seek to reduce their capacity when no supply cost reduction results from their doing so. This is not, in principle, different to the Authority's concern about consumer response to consumption-based pricing. The nature of electricity networks is that there is very significant diversity in electrical loadings for most types of customers. For example, the average anytime maximum demand (AMD) of residential customers on the Orion network is between 7kW and 8 kW, 3 to 4 times greater than their after diversity maximum demand (ADMD, sometimes called coincident maximum demand or CMD) of 2 kW to 3 kW.[21] This high diversity factor allows transmission and distribution networks to be built largely based on the lower ADMD, while still being able to support much higher AMDs close to connections. In essence, capacity based charging poses similar problems to consumption based charging: it is not cost reflective, and is distortionary (customers will change their behaviour inefficiently),

[20] This discussion focusses on our 'general' connections category which encompasses all residential customers as well as most small and medium sized businesses.

[21] This analysis uses interval data from a sample of around 2,200 (out of around 160,000) residential connections. These demands are averages measured over the half-hour intervals. Instantaneous maximum demands would usually materially exceed - and by definition cannot be less than - these values.

- It may lead customers to believe they have a 'right' to their stated nominated capacity, when the upstream network is actual configured (efficiently) to only support ADMD. This is an area where the telecommunications / broadband analogy falls down. With telecommunications, higher coincident demands can be managed via reductions in connection speed for all. The electrical equivalent is voltage, which for regulatory and safety reasons cannot be reduced materially. Overloading an electrical network results in outages rather than slower speeds.

These are not reasons to not make changes, just examples of why caution is needed.

As well as the Authority's concerns about consumption-based charges, retailers[22] have for many years expressed concerns about the other key component of our pricing, the peak demand component. This component uses a demand measure based on coincident demands during our dynamically signalled peak periods, which occur in winter. It involves estimation and wash-ups, and, to the extent that retailers rebundle it into consumption-based prices it involves some risk. Any move away from this form of pricing that addresses retailer concerns is likely to compromise economic efficiency. The Authority, in its pricing principles and practice note, has not provided guidance on the trade-off between efficiency and simplicity.

Our own (2017 & 2018) consultation and feedback has re-confirmed retailer concerns about the complexity of our current approach to peak pricing. We believe that that most forms of so-called TOU pricing are inconsistent with our approach to load management, and will ultimately create loading peaks when customers respond to the pricing differences and load diversity is reduced. In light of this we proposed alternative approaches (rebates for controllable load, or reward pricing) but these alternative did not receive support. In our 2018 consultation we sought to further explain our concerns about the ability of TOU pricing to deliver efficient outcomes. The majority of responses supported a TOU approach without addressing our concerns about the conflict with load management and creation of peaks.

Separate to these considerations, we have now included a sustainability element within our pricing strategy, and we will consider the impact that pricing changes will have on sustainability outcomes.

The Authority's TPM work is also relevant. While, under the most recent proposal, much of the detail is to be left to Transpower, it is clear that the Authority sees that the majority of transmission charges should be either unavoidable or difficult to avoid. While this is fairly orthodox network economics in relation to recovery of common cost elements, it is difficult to see how it squares with the low fixed charge regulations or guidelines. This reinforces our view that the revocation of the regulations is necessary for introducing cost reflective pricing.

Next steps

With the considerations above, we:

- await the outcome of changes to the LFC regulations (which currently effectively prevent further fixed charges and tiered pricing),
- await the outcome of the TPM review,
- continue to explore options to address the compatibility issues with TOU pricing, and
- will encourage dialogue to resolve the divergent views we receive on the use of peak pricing.

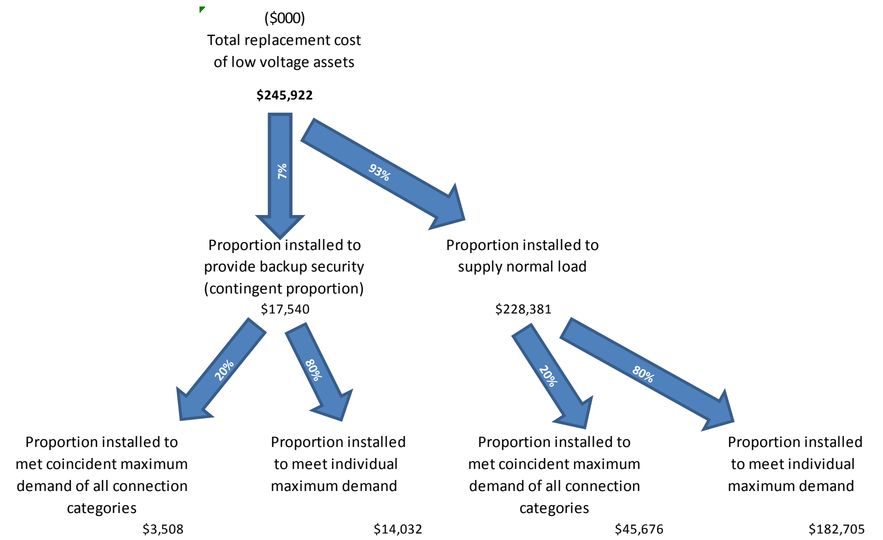
[22] Not all retailers have the same views, but we consider it is accurate to say this this is the predominant view among retailers, both the large and established and the new entrants.

Appendix D - Asset allocation example

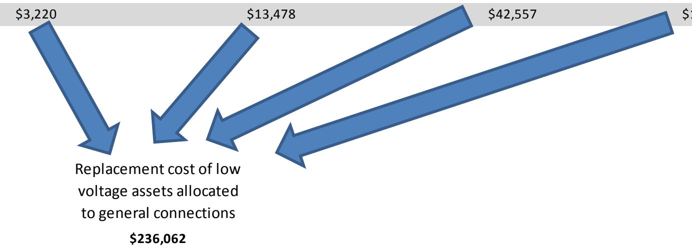
Example calculation

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	$16.00/kWh	$16.00/kWh		
AMD Loading		1,981,824 kW		1,981,824 kW
ADMD Loading	472,025 kW		472,025 kW	
Product of allocators (N)	7,552,438	31,709,343	472,025	1,981,824
Product of allocators across all connection categories (D)	8,227,153	33,013,959	506,618	2,047,935
Allocation proportion (N / D)	91.8%	96.0%	93.2%	96.8%
Allocated asset value	$3,220	$13,478	$42,557	$176,807



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	615.0 MVA
Lower LV network	498.2 MVA

Step 2

Estimate the replacement cost of the network

Upper HV network	$1,103 m
Lower LV network	$443 m
Total replacement cost	$1,546 m

Step 3

Estimate the proportion of replacement cost that is load dependent

Upper HV network	$629 m
Lower LV network	$207 m
Total replacement cost	$836 m

Step 4

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

Upper HV network	$526 m
Lower LV network	$61 m
Total replacement cost	$587 m

Step 5

Calculate load dependent replacement cost per kVA

Upper HV network	$856 /kVA
Lower LV network	$123 /kVA
Total replacement cost	$978 /kVA

Step 6

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

Upper HV network	$74 /kVA/year
Lower LV network	$10 /kVA/year
Total	$84 /kVA/year

See notes for each step on next page.

Notes

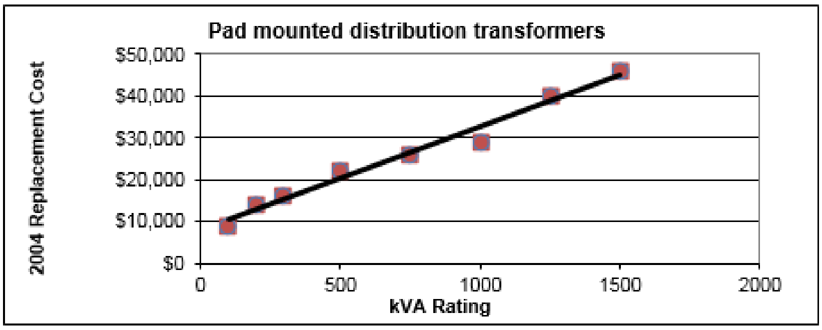
Step 1
This is the combined coincident peak demand of all loads

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 clause 2.4.1 of the Electricity Distribution Information Disclosure Determination 2012, in all material respects complies with that determination.

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

Deborah Jane Taylor

Bruce Donald Gemmell

24 February 2020