

Methodology for deriving delivery prices

For prices applying from 1 April 2018

Issued xx February 2018

DRAFT

**Please note that this document has not yet been certified by Orion's directors
A certified version is expected to be issued in February 2018.**

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Glossary of abbreviations

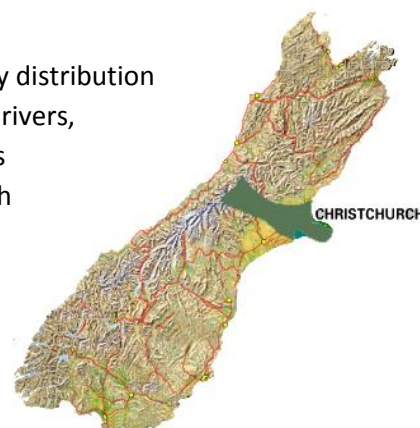
The following abbreviations are used in this document:

- **ADMD**, for *after diversity maximum demand*. Customers¹ 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. Applies 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.
- **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

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 locations² and we distribute this electricity to more than 200,000 homes and businesses.



New Zealand's South Island

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 typically amount to around 40% of a 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 The number has reduced in recent years due to our programme of acquiring Transpower's 'spur' assets. 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.

2.1 Economic considerations

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 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 encourage 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.

2.3 Return on investment

We operate our business in a commercial environment and, to ensure continued and appropriate investment in our network (including for the long term benefit of customers), we aim to meet the expectations of our shareholders – particularly in relation to providing commercially realistic returns on the value of their investment.

However, the most significant factor currently influencing our return on investment is the customised price-quality path (CPP) determined for Orion by the Commerce Commission (the “Commission”). The Commission’s decision is described in more detail in section 2.6 below.

The Commission has applied a WACC of 6.92%³ in calculating our CPP, and, in this document we estimate our return with respect to this CPP WACC. However, it is important to note that it is our prices that are regulated, not our return on investment. Our actual returns over the CPP period will differ from 6.92% due to:

- timing: the CPP is designed to give us the WACC return over the full CPP period, not in any one year. In particular we would expect returns in the first years to be lower, and in later years higher, due to the way the price path has been smoothed,
- differences between the Commission’s views about what our capital and operating expenditure should be, and what we actually spend, and
- differences between assumed and actual growth.

2.4 Regulatory considerations

The principal regulatory requirement that we seek to comply with is the customised 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 guidelines administered 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,
- 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 prices⁴,
- 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 Cost of capital determination for electricity distribution businesses to apply to a customised price-quality path proposal [2012] NZCC 25.

⁴ 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 both aimed at ensuring the long term interests of consumers are met. That is consistent with Orion's objectives.

Our pricing strategy (see section 2.8 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

There has been no material change to Orion's pricing methodology since the last methodology was published in February 2017.

In response to the Authority's continuing work on distribution and transmission pricing we have set out our current plans for possible future pricing changes in appendix C.

2.6 Customised price-quality path

The earthquakes in the Canterbury region in 2010 and 2011 had a significant impact on Orion's business. Increased capital and operating expenditure, and lower revenues from reduced chargeable quantities, cost us tens of millions of dollars over several years, and these effects will continue for some time. Parts of the network (in the eastern suburban red-zone areas) have become stranded, and at the same time we are investing in ongoing development in new western and northern suburban areas to supply substantially the same load. In addition, replacement of assets will be at higher cost. We have had to change the way we build the network to accommodate the significant amount of ground movement that we now know can occur in the eastern suburbs.

From early 2012 we worked on a customised price-quality path (CPP) proposal to address the financial and reliability impact of the earthquakes. This was submitted to the Commerce Commission in February 2013. The Commission then considered our proposal and issued a final determination on 29 November 2013. This determination provided for an initial more significant increase which we applied from 1 April 2014, followed by annual increases at 1% above the rate of inflation for the following four years. The prices to apply from 1 April 2018 are the last prices to be calculated under our CPP.

There has been no material change to the principles of our pricing methodology, or our overall conceptual approach, as a result of the CPP.

2.7 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 have been sought in the price-setting process.⁵

⁵ Commerce Commission, Decision NZCC 22: Electricity Distribution Information Disclosure Determination 2012, 2.4.1 (4). The Determination uses the term consumer rather than customer.

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 and, in Orion's case the recent CPP process. These processes allow consideration of meaningful trade-offs between our new 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 this will, over time, be reflected in changes in the real prices that customers pay, and the quality of supply they receive,
- the Commission's final decision on our CPP reflects consultation carried out by both Orion and the Commission. It clearly links planned operating and capital expenditure - and therefore our prices - to our quality targets for the CPP period, and
- further consultation as part of the price-setting process would involve considerable duplication of the AMP / CPP process.

However, we have consulted with customers, by way of focus groups, on the challenges and re-distributional consequences of having prices based largely on volumes when supply costs are fixed, and particularly in the context of the potential for some customers to invest in technologies such as solar PV.

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.

We do undertake consultation when we propose any changes to the structure of our pricing. The last such consultation occurred in August and September 2017.

2.8 Pricing strategy

Our high level pricing strategy was formally approved by the Orion board at its meeting on 7 December 2017. The strategy is as follows⁶:

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.

⁶ Pursuant to section 2.4.4 of the information disclosure determination (IDD), and further to the discussion in section 3.2 below. Subsequent to the approval of this strategy, Transpower has announced that it is not proceeding with the referenced operational review.

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.

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

- apply price averaging over large numbers of connections, because it is generally not practicable to single out individual connections for cost-reflective delivery pricing. Where it is practicable to do so we allocate assets and costs to the specific connection categories that use them.
- recognise that all consumers should share in the benefits of greater utilisation of shared assets and economies of scale.
- recognise that consumers generally change their demand behaviour over relatively long periods of time and it is important that we provide compelling and consistent pricing incentives aimed at maximising the efficient utilisation of our assets (for example, our low off peak prices encourage consumers to shift load away from expensive peak periods to off-peak).
- 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:

- 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.
- a signalled review of the low fixed charge regulations.
- the Electricity Authority’s:
 - continued interest in distribution pricing methodologies and its expectation that we will continue to keep it informed of developments,
 - published guidance about how it will interpret aspects of the low fixed charge regulations which might allow wider use of capacity-based pricing,
 - continuing review of Transpower’s transmission pricing methodology (TPM),
 - implemented changes to the Code that EDBs will not in future (for Orion from 1 October 2019) be able to recover payments made to generators that reflect the avoided cost of transmission (ACOT)
- Transpower’s operational review of the TPM.

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.⁷

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 services.

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,
 - asset depreciation, asset disposal losses and return on capital invested,
 - tax,
 - operations and maintenance costs,
 - administration costs,
 - pass through costs such as local authority rates and regulatory agency levies,
 - 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 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
- estimate the long run average incremental cost (LRAIC) of investment in our network

⁷ And, to an increasing extent, we deliver electricity produced at customer connections.

- 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 ‘time-of-use’ and ‘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 support customer choice.

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.⁸ 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

This pricing methodology is primarily focussed on the year ahead – April 2018 to March 2019.

This section⁹ comments on anticipated trends in cost drivers and pricing over the next five years and in particular, given Orion’s post-quake circumstances, on the outcomes of our CPP. This section is not as detailed as, and is not intended to be a substitute for, the material in our AMP, our CPP proposal or the Commission’s documents.

Pricing for the next five years

The year from 1 April 2018 is the last year under our CPP as determined by the Commission in November 2013:¹⁰

⁸ For example, the average delivery cost (for the retailer on a cents per kWh basis) for a customer with solar panels (PV) might be higher than a customer without them, while the average cost for customers that use gas for space heating might be lower than that of customers that do not.

⁹ 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 2.8 includes the pricing strategy approved by the Orion board.

¹⁰ For full details see the various papers and documents on the Commission’s website:
<http://www.comcom.govt.nz/regulated-industries/electricity/cpp/orion-cpp/>.

From 1 April 2019 the Commission has decided that our prices from the previous year will roll over, with a CPI adjustment and a deduction for the 'clawback' that we are recovering in the CPP period.¹¹ Then, from April 2020, our prices will, if Orion remains on the DPP, be determined according to the methodology for the 2020 reset that the Commission will establish over the next year or so. Of particular note is that the form of control will change from a weighted average price cap to a revenue cap.

Separately, we are likely to face changes in transmission costs over the next five years.

- Transpower has signalled small changes in its revenue requirement after 2018/19 through to the end of its 'RCP2' in 2019/20.
- The Authority has, over a number of years, proposed significant changes to the transmission pricing methodology (TPM) which could, if implemented, dramatically change the level and incidence of transmission costs. At this stage we think it unlikely that any TPM changes will take effect before April 2020.

New and emerging technologies

Like most distributors, Orion is seeing a rapid increase in the uptake of photo-voltaic (PV) generation, mostly on houses. The Electricity Authority has highlighted the fact that, while on-site generation can have economic benefits, some electricity customers can end up subsidising others if pricing is distorted. Orion shares this view, in particular that the low fixed charge regulations tend to make the variable components of delivery prices higher than they should be, which means the value of offset consumption (typically 25 to 30 cents per kWh) is much more than the reduction in network costs (which is effectively zero for PV). The Authority issued a consultation paper in November 2015 on distribution pricing in the context of emerging technologies. The paper challenges the dominant distributor view, shared by Orion, that we are significantly constrained by the low fixed charge regulations. The Authority has followed up with guidance on how it will interpret the regulations particularly with respect to what sort of charges it would see as variable. We are still considering the implications of this.

More broadly, the Authority's work has led to it setting out expectations of distributors in implementing more cost reflective and service based pricing. This is discussed more fully in appendix C below.

We are also keeping an eye on developments with batteries and electric vehicles (EVs). Key for us is how people decide when to charge them, and, in the case of batteries, when to discharge them. We believe even very significant EV uptake can be accommodated on our existing network so long as charging occurs at off-peak times (for example overnight). However, if most charging occurs at peak times this could require additional network investment. Also, as EV numbers increase, the coincidence of the commencement of charging (at any time) could present challenges.

Changes to pricing strategy

Other than accommodating the changing factors noted above, there have been no changes to our pricing strategy.

¹¹ See "Electricity Distribution Services Default Price-Quality Path Amendment Determination 2016 [2016] NZCC 19", at <http://www.comcom.govt.nz/dmsdocument/14806>.

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.

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. We switch these circuits 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.¹²

Assessed key statistics for streetlighting connections (1 April 2018 to 31 March 2019)	Forecast
Number of chargeable connections	48,876 (average)
Number of ICPs	530 (average)
Energy volume	25,942 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	2,787 kW
– contribution to network-wide summer peak (ADMD)	216 kW
– contribution to local network peak (ADMD)	2,787 kW
– sum of individual connection anytime peaks (ΣAMD)	6,175 kW
Value of lost load (VOLL)	\$14.86 / kWh

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

¹² There is a small but increasing number of streetlights that are not connected to our dedicated 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 reason to separately consider any subset of this category.

Assessed key statistics for general connections (1 April 2018 to 31 March 2019)	Forecast
Number of connections / ICPs	197,429 (average)
Energy volume	2,295,426 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	486,017 kW
– contribution to network-wide summer peak (ADMD)	280,307 kW
– contribution to local network peak (ADMD)	486,017 kW
– sum of individual connection anytime peaks (Σ AMD)	2,048,824 kW
Value of lost load (VOLL)	\$15.51 / kWh

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

4.3 Irrigation connections

We provide a specific irrigation connections 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 2018 to 31 March 2019)	Forecast
Number of connections / ICPs	1,047 (average)
Energy volume	138,871 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	0 kW
– contribution to network-wide summer peak (ADMD)	33,605 kW
– contribution to local network peak (AMD)	53,093 kW
– sum of individual connection anytime peaks (Σ AMD)	90,793 kW
Value of lost load (VOLL)	\$1.18 / kWh
Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurements (i.e. with normal distribution losses added).	

4.4 Major customer connections

We provide a specific category for our larger connections. 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 200 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 will not be categorised as major customer connections,
- reconciled embedded networks will be classified as major customer connections.

A number of factors affect our cost allocations for these connections, including:

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

In addition to these factors, all connections of this size have half-hour interval metering which gives Orion the opportunity to apply more specific cost-reflective pricing using the metered volumes for each connection.

Assessed key statistics for major customer connections (1 April 2018 to 31 March 2019)	Forecast
Number of connections / ICPs	437 (average)
Energy volume	826,670 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	104,772 kW
– contribution to network-wide summer peak (ADMD)	119,342 kW
– contribution to local network peak (ADMD)	104,772 kW
– sum of individual connection anytime peaks (ΣAMD)	213,086 kW
Value of lost load (VOLL)	\$22.22 / kWh
Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurements (i.e. with normal distribution losses added).	

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.

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.

Assessed key statistics for large capacity connections (1 April 2018 to 31 March 2019)	Forecast
Number of connections / ICPs	12 (at 2 locations)
Number of customers	2
Energy volume	115,913 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	5,000 kW
– contribution to network-wide summer peak (ADMD)	18,700 kW
– contribution to local network peak (ADMD)	18,700 kW
– sum of individual connection anytime peaks (ΣAMD)	23,000 kW
Value of lost load (VOLL)	\$58.44 / 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 category 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.

5 Total costs

Considering 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 2018 - 2019 year, which gives us our total target revenue:

Cost component (1 April 2018 to 31 March 2019)	Forecast \$000
Transpower's interconnection charges	65,836
Transpower's connection and new investment charges	7,054
Avoided transmission costs	3,927
Payments to distributed generators in lieu of transmission charges	132
Transmission subtotal	76,948
Payments to distributed generators in lieu of distribution costs	62
Administration costs	15,234
Operations and maintenance costs	46,761
Pass through costs ¹³	4,952
Payments for interruptible load and power factor correction	1,114
Depreciation	40,000
Loss on disposals	2,000
Asset value (average regulatory asset base, \$000) ¹⁴	1,044,000
Applicable WACC	6.92%
Return on capital (after tax) ¹⁵	67,066
Less revenue received from avoided transmission charges	(3,927)
Less sundry revenue	(4,340)
Taxation	24,200
Cost allocation discount to meet CPP requirement	(8,288)
Distribution subtotal	184,834
Delivery total (total target revenue)	261,783

¹³ Includes rates of \$3,810k, Electricity Authority levies of \$635k, Commerce Commission levies of \$400k and Utilities Disputes levies of \$107k.

¹⁴ This is our forecast average regulatory asset base (RIV) for the 2018 – 2019 year based on our disclosed RIV prepared in accordance with the Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2012.

¹⁵ $\$1,044,000 \times 6.92\% \times (1 - 28\% \times 25.6\%) = \$67,066\text{k}$.

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 (Σ AMD)
- 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 sources¹⁶ and ranges between \$1 and \$58 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 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.

¹⁶ 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	1,118	197,356	22,072	47,905	4,773	273,223
Power Transformers	179	31,774	2,321	7,914	2,849	45,037
11kV Distribution	1,082	201,539	26,603	53,288	784	283,297
Land & Property	213	70,790	2,927	7,593	1,806	83,329
Distribution Transformers	298	85,142	4,549	8,101	59	98,148
Low voltage distribution	84	238,384	1,270	6,183	0	245,922
Lighting	14,577	0	0	0	0	14,577
Total	17,551	824,985	59,741	130,985	10,270	1,043,532

* 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 only a very small share (3%) of the low voltage distribution network assets when compared with their share of subtransmission (18%) and 11kV distribution assets (19%). 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	17,572	825,989	59,814	131,144	9,481	1,044,000

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

6.2 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 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 (Σ AMD).

Finally, we allocate the cost of any transmission alternatives that we procure:

- the avoided transmission investment is allocated according to Σ AMD as it is an alternative to connection assets, and
- the transmission components of our export and generation credits reflect the savings in Transpower's charges that result from reduction in winter peak demands, and are therefore allocated using ADMD.

In summary:

	Street lighting \$000	General \$000	Irrigation \$000	Major customer \$000	Large capacity \$000	Total \$000
Transpower's interconnection charges	203	48,680	1,848	13,734	1,371	65,836
Transpower's connection and new investment charges	16	5,308	235	552	942	7,054
Avoided transmission investment	10	3,411	151	355	0	3,927
Transmission component of export and generation credits	1	107	0	23	1	132
Transmission cost allocation	230	57,506	2,234	14,664	2,314	76,948

6.3 Distributed generation distribution cost allocation

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

	Street lighting \$000	General \$000	Irrigation \$000	Major customer \$000	Large capacity \$000	Total \$000
Distribution component of export and generation credits	0	47	5	10	0	62

6.4 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 \$000	General \$000	Irrigation \$000	Major customer \$000	Large capacity \$000	Total \$000
Payments for rebates	19	889	64	141	0	1,114

6.5 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 (Σ AMD), as this reflects the extent to which each connection utilises our service. The resulting allocation is:

	Street lighting \$000	General \$000	Irrigation \$000	Major customer \$000	Large capacity \$000	Total \$000
Administration cost allocation	40	13,132	582	1,366	115	15,234

6.6 Operations and maintenance cost allocation

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

	Street lighting \$000	General \$000	Irrigation \$000	Major customer \$000	Large capacity \$000	Total \$000
Operations and maintenance cost allocation	788	37,055	2,683	5,883	351	46,761

6.7 Pass through cost allocation

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

	Street lighting \$000	General \$000	Irrigation \$000	Major customer \$000	Large capacity \$000	Total \$000
Pass through cost allocation	83	3,924	284	623	38	4,952

6.8 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. The resulting cost allocations are:

	Street lighting \$000	General \$000	Irrigation \$000	Major customer \$000	Large capacity \$000	Total \$000
Depreciation cost allocation	676	31,756	2,300	5,042	227	40,000
Loss on disposals	34	1,597	116	254	0	2,000
Applicable WACC (6.92%)	1,127	52,969	3,836	8,410	724	67,066
Taxation cost allocation	409	19,214	1,391	3,051	135	24,200
Costs funded by avoided transmission	(10)	(3,411)	(151)	(355)	0	(3,927)
Costs funded by sundry revenue	(11)	(3,770)	(167)	(392)	0	(4,340)
Total cost of capital allocation	2,224	98,355	7,324	16,009	1,087	124,999

6.9 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 customised price-quality path.

When applying this discount, we consider the impact of any changes in our cost allocation from 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 6.2 to 6.8 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	230	57,506	2,234	14,664	2,314	76,948
Cost discount	0	48	(60)	12	0	0
Target transmission revenue	230	57,554	2,174	14,676	2,314	76,948
Distributed generation cost allocation	0	47	5	10	0	62
Payments for rebates	19	889	64	141	0	1,114
Administration cost allocation	40	13,132	582	1,366	115	15,234
Operations and maintenance cost allocation	788	37,055	2,683	5,883	351	46,761
Pass through costs	83	3,924	284	623	38	4,952
Total cost of capital allocation	2,224	98,355	7,324	16,009	1,087	124,999
Cost discount	(166)	(6,227)	(930)	(964)	0	(8,288)
Target distribution revenue	2,988	147,175	10,013	23,069	1,590	184,834
Total target revenue	3,217	204,729	12,188	37,745	3,904	261,783
Resulting return on capital	5.9%	6.1%	5.1%	6.1%	8.2%	6.0%

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 and generation 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.¹⁷

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.

The LRAIC is updated every year.

¹⁷ 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

The LRAIC is not intended to support pricing as a means of managing localised or short term capacity issues. Rather, it is an estimate of the how much it typically costs us to provide a distribution network solution to support demand. This can then be set against alternatives, and in particular demand response.

7.2 Streetlighting connections

Energy used by streetlighting connections is subject to our general connection prices applied to GXP reconciled volumes (including peak demands). These prices provide incentives to maximise the efficiency of lights, but the revenue collected does not cover the additional cost to provide our dedicated lighting circuits.

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.

Chargeable quantity	Distribution part	Transmission part	Distribution revenue \$000	Transmission revenue \$000
Fixed daily charge				
48,876 connections	0.1254 \$/connection/day	(0.0043) \$/connection/day	2,237	(77)
Peak charge				
2,528 kW	0.3288 \$/kW/day	0.1893 \$/kW/day	303	175
Volume charges				
<i>Weekdays (Mon to Fri, 7am to 9pm)</i>				
3,330 MWh	0.07347 \$/kWh	0.01969 \$/kWh	245	66
<i>Nights & weekends (Sat & Sun)</i>				
22,612 MWh	0.00896 \$/kWh	0.00297 \$/kWh	203	67
Total revenue			2,988	231
<i>compared with target revenue (from section 6.9)</i>			2,988	230

7.3 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 calculations support an LRAIC of \$98 per kW per year for general connections. With the current price adjustments our price is set above this level at \$120 per kW per year (expressed as a daily price of \$0.3288 per kW per day) and we expect to be able to reduce this gap over future years.

In addition, a significant proportion of Transpower's charges to us are based on peak loadings and this is reflected in the transmission peak price.

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 balance of our revenue requirement for both distribution and transmission is collected through our volume charges. We have structured the volume charges to reflect the value of our service to each customer, and we have applied a day / night differential to reinforce our peak based pricing incentive and encourage better utilisation of our network. Volume-based charging also supports compliance with low fixed charge regulations.

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
Volume charges				
<i>Weekdays (Mon to Fri, 7am to 9pm)</i>				
1,084,692 MWh	0.07347 \$/kWh	0.01969 \$/kWh	79,692	21,358
<i>Nights & weekends (Sat & Sun)</i>				
1,210,734 MWh	0.00896 \$/kWh	0.00297 \$/kWh	10,848	3,596
Peak charge				
471,860 kW	0.3288 \$/kW/day	0.1893 \$/kW/day	56,629	32,603
Low power factor charge				
0 kVAR	0.1500 \$/kVAR/day	0.0500 \$/kVAR/day	-	-
Total revenue			147,169	57,556
<i>compared with target revenue (from section 6.9)</i>			147,175	57,554

7.4 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 poor 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)

Many 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				
<i>Chargeable pump capacity</i>				
73,151 kW	0.3759 \$/kW/day	0.0591 \$/kW/day	5,005	787
Volume charges				
<i>Weekdays (Mon to Fri, 7am to 9pm)</i>				
58,347 MWh	0.07347 \$/kWh	0.01969 \$/kWh	4,287	1,149
<i>Nights & weekends (Sat & Sun)</i>				
80,524 MWh	0.00896 \$/kWh	0.00297 \$/kWh	721	239
Rebates*				
<i>Power factor correction</i>				
22,845 kVAr	(0.1793) \$/kVAr/day	-		
<i>Interruptibility</i>				
45,198 kW	(0.0448) \$/kW/day	-		
Total revenue			10,013	2,175
<i>compared with target revenue</i> (from section 6.9)			10,013	2,174

* Rebates are not included in the total revenue because they are funded across all connection categories (see section 6.4).

7.5 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 \$90 per kVA per year. With the current price adjustments our price is set above this level at \$107 per kVA per year (expressed as a daily price of \$0.2939 per kVA per day) and we expect to be able to reduce this gap over future years.

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 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 through the prices that are applied to customers' maximum demands.¹⁸

In relation to the transmission component, a significant proportion of Transpower's charges to us are based on peak loadings and this is reflected in the transmission price for control period demand. We recover the balance of the transmission allocation via capacity charges.

¹⁸ 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 charges				
<i>Daily connection charge</i>				
437 connections	7.5000 \$/connection/day	-	1,196	-
<i>Extra switches</i>				
111 switches	3.6100 \$/switch/day	-	146	-
<i>11kV Metering equipment</i>				
52 connections	4.3700 \$/connection/day	-	83	-
<i>11kV Underground cabling</i>				
5.10 km	3.2300 \$/km/day	-	6	-
<i>11kV Overhead lines</i>				
3.20 km	2.0300 \$/km/day	-	2	-
<i>Transformer capacity</i>				
301,795 kVA	0.0135 \$/kVA/day	-	1,487	-
Capacity charges				
<i>Nominated maximum demand</i>				
239,164 kVA	0.0994 \$/kVA/day	0.0108 \$/kVA/day	8,677	943
<i>Metered maximum demand</i>				
214,461 kVA	-	0.0862 \$/kVA/day	-	6,748
Control period demand charges				
106,883 kVA	0.2939 \$/kVA/day	0.1791 \$/kVA/day	11,466	6,987
Total revenue			23,064	14,677
<i>compared with target revenue</i> (from section 6.9)			23,069	14,676

7.6 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 and the table below shows projected revenue.

Chargeable quantity	Distribution part	Transmission part	Distribution revenue \$000	Transmission revenue \$000
Distribution charges (including amortisation of prepaid charges via development contribution)			1,590	-
Transmission charges			-	2,314
Total revenue			1,590	2,314
<i>compared with target revenue (from section 6.9)</i>			1,590	2,314

7.7 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 2018 - 19, and shows how this (and associated prices) have changed compared to the projection for the previous (2017 - 18) year:

	Street lighting	General	Irrigation	Major customer	Large capacity	Total
	\$000	\$000	\$000	\$000	\$000	\$000
<i>Projected revenue 2018-19</i>						
Distribution	2,988	147,169	10,013	23,064	1,590	184,824
Transmission	231	57,556	2,175	14,677	2,314	76,953
Delivery	3,218	204,726	12,188	37,741	3,904	261,777
<i>Revenue change compared to previous year</i>						
Distribution	116	7,488	(100)	2,913	(11)	10,407
Transmission	(23)	(1,062)	(232)	982	187	(147)
Delivery	93	6,426	(332)	3,895	177	10,259
<i>Estimated price change compared to previous year¹⁹</i>						
Distribution	5.7%	4.0%	6.6%	4.8%	(8.2%)	4.2%
Transmission	2.0%	(2.3%)	(1.7%)	(0.8%)	(3.9%)	(2.1%)
Delivery	5.4%	2.2%	5.0%	2.5%	(5.6%)	2.3%

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.

Overall distribution price movements reflect the CPP determination applicable to Orion at this time. Revenue is then the CPP compliant distribution prices multiplied by the projected quantities.

Overall transmission price movements reflect changes in transmission costs and in the projected quantities over which they are recovered.

¹⁹ Note that these percentages represent price movements whereas the revenue changes described in the same table are the result of both price movements and quantity movements.

8 Credits for export and generation

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. Separately, generators that respond to our signal at other times can also assist with capacity constraints, enhancing security of supply and service quality, and this benefit is reflected in our generation credits.

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 (export credits and generation credits) 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 sections 6.2 and 6.3 above show the assignment of these costs to connection categories.

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 \$98 per kW per year (as noted in section 7.3 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. Consequently, we set the distribution credit price below the full LRAIC to reflect this.

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.

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. We have assessed the extent to which generation during our signalled peak and control periods will reduce these chargeable loadings and this is reflected in the transmission component of our export credits.

Generation credit prices

The generation credit arrangement was established to reduce loading levels via generation support at other times, and the credit is based on electricity generated, regardless of whether this is used within the connection or exported onto our network. We set the price at a level that is sufficient to attract the required level of load reduction. The arrangement has not provided the benefits anticipated and has posed considerable technical and administrative challenges. As a result, from 1 April 2017 we closed the arrangement to new generation, and will reconsider the future of the scheme for existing participating generation in future reviews.

Appendix A - Price schedules

Electricity delivery price schedule for Orion NZ Ltd

(applicable from 1 April 2018)



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.

All prices exclude GST	Price Component Code ³	Distribution Part	Transmission Part	Delivery Price	Unit of measure
Streetlighting connections		approx 48,876 connections			
Fixed charge	STFXD	0.1254	(0.0043)	0.1211	\$/con/day
Peak charge (peak period demand)	GENPK	0.3288	0.1893	0.5181	\$/kW/day
Volume charge					
Weekdays (Mon to Fri, 7am to 9pm)	VOLWD	0.07347	0.01969	0.09316	\$/kWh
Nights & weekends (Sat & Sun)	VOLNW	0.00896	0.00297	0.01193	\$/kWh
General connections		approx 197,429 connections			
Peak charge (peak period demand)	GENPK	0.3288	0.1893	0.5181	\$/kW/day
Volume charge					
Weekdays (Mon to Fri, 7am to 9pm)	VOLWD	0.07347	0.01969	0.09316	\$/kWh
Nights & weekends (Sat & Sun)	VOLNW	0.00896	0.00297	0.01193	\$/kWh
Low power factor charge	LOWPF	0.1500	0.0500	0.2000	\$/kVA/day
Irrigation connections		approx 1,047 connections			
Capacity charge	ICCAP	0.3759	0.0591	0.4350	\$/kW/day*
Volume charge					
Weekdays (Mon to Fri, 7am to 9pm)	VOLWD	0.07347	0.01969	0.09316	\$/kWh
Nights & weekends (Sat & Sun)	VOLNW	0.00896	0.00297	0.01193	\$/kWh
Rebates					
Power factor correction rebate	ICPFC	(0.1793)		(0.1793)	\$/kVA/day*
Interruptibility rebate	ICIRR	(0.0448)		(0.0448)	\$/kW/day*
* applied from 1 October to 31 March only					
Major customer and embedded network connections		approx 437 connections			
Fixed charge	MCFXD	7.5000		7.5000	\$/con/day
Extra switches	EQESW	3.6100		3.6100	\$/switch/day
11kV Metering equipment	EQMET	4.3700		4.3700	\$/con/day
11kV Underground cabling	EQUGC	3.2300		3.2300	\$/km/day
11kV Overhead lines	EQOHL	2.0300		2.0300	\$/km/day
Transformer capacity	EQTFC	0.0135		0.0135	\$/kVA/day
Peak charge (control period demand)	MCCPD	0.2939	0.1791	0.4730	\$/kVA/day
Nominated maximum demand	MCNMD	0.0994	0.0108	0.1102	\$/kVA/day
Metered maximum demand	MCMMD		0.0862	0.0862	\$/kVA/day
Large capacity connections		12 connections			
Individually assessed prices advised and charged directly to the customers					
Miscellaneous					
Monthly invoice and contract charge to retailers and directly contracted customers	INVFXD	30.00		30.00	\$/invoice

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.
3. The price component code is used in our mandatory 'electricity information exchange protocol' files.

Export and generation credit schedule for Orion NZ Ltd



(applicable from 1 April 2018)

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 further details refer to our *Export and Generation Credits Policy* document, available on our website.

Export credit pricing (excluding GST)

Orion provides credits for electricity exported on to Orion's network during specified periods. The prices for these credits are:

Generator rated output	Period applied	Price Component Code ³	Credit Price	Unit of measure
0 - 30kW generation ²				
Anytime credits (without PV), or	Anytime	EXPA	0.00920	\$/kWh
Anytime credits (with PV)	(24 hours, 7 days)	EXPAPV	0.00030	\$/kWh
0 - 30kW generation ²				
Peak period credits (with or without PV)	Chargeable peak period	EXPPP	0.64290	\$/kWh
30 - 750kW Control period credits ⁴				
- real power, plus	Chargeable control period	EXPCP1	0.2202	\$/kW/day
- reactive power ⁵		EXPCP2	0.0277	\$/kVar/day
above 750kW	Individually assessed prices provided on application			

Notes for export credit pricing

- Full details covering generation and metering requirements and application of prices are included in our *Export and Generation Credits Policy* document, available on Orion's website.
- 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.
- The price component code is used in our mandatory 'electricity information exchange protocol' files.
- Control period credits are assessed during control periods and applied as an annual credit at 365 times the daily credit price.
- 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.
- Approximately 14 connections are approved for export credits.

Generation credit pricing (closed) (excluding GST)

The generation credits arrangement is closed and is not available to any new generation. For existing participating generation we signal "generation periods" and provide a credit that reflects generation support provided at times when the export credit (above) is not available. These credits are based on the generated volume, regardless of whether this results in export from the connection.

Generator rated output	Period applied	Price Component Code ³	Credit Price	Unit of measure
All participating generation (not available to any further generation)	Orion's ripple signalled generation period	GEN1	0.50000	\$/kWh

Notes for generation credit pricing

- Full details covering generation and metering requirements and application of prices are included in our *Export and Generation Credits Policy* document, available on Orion's website.
- These prices apply for the current group of approved generation during our ripple signalled generation period. The total duration of generation periods is likely to vary significantly from year to year. In some years there may be no generation periods.
- The price component code is used in our mandatory 'electricity information exchange protocol' files.
- Approximately 9 connections are approved for generation credits.

Appendix B - Electricity Authority pricing principles and information disclosure guidelines, and Commerce Commission Information disclosure requirements

Introduction

This appendix outlines and comments on the aspects of this methodology that relate to the regulatory requirements of the Electricity Authority (the “Authority”) and the Commerce Commission (the “Commission”).

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, while the disclosure guidelines allow interested parties to see the extent to which this is happening. The Authority inherited these guidelines on its establishment in November 2010.

Under the guidelines distributors are to prepare and disclose a statement of the alignment of their pricing with the principles. The Authority will then review these disclosures with a view to informing further work in this area.

The Authority retained Concept Consulting to carry out a preliminary review of a subset of (nine) distributor pricing methodologies in 2011. As a result, some criteria and additional information requirements were proposed and consulted on by the Authority in October 2011, but no changes to the principles and guidelines were made as a result. We have reflected *some* of Concept’s comments and suggestions in our methodology.

Then, in December 2013, Castalia completed an Authority-commissioned review of distributors’ pricing methodologies against the principles and guidelines.²⁰

Some of Castalia’s findings and suggestions have been reflected in changes to our methodology. Moreover we endorse Castalia’s recommendations as to the appropriateness of principles-based regulation and its suggestions to the Authority on ways that the regime might be improved.²¹ We also acknowledge both the importance and difficulty of engaging with customers over pricing, although in our view it is consultation as part of asset management planning that is more important to pricing, as it is primarily by that means that material changes to our costs can be achieved – via different investment and maintenance decisions – and it is only by *changing* our costs in some fundamental way that there can be a material effect on our prices. In a steady state situation by contrast – with normal maintenance and normal growth related capital expenditure – there is no reason to suppose any strong relationship between asset management planning and pricing.

There are some areas of Castalia’s reports that need further discussion as the benefits of some of the recommendations are not clear to us.

In terms of its summary paper, for example:

²⁰ Castalia’s review of our 2013/14 methodology can be found on the Authority’s website: <http://www.ea.govt.nz/dmsdocument/16296>.

²¹ In Castalia’s summary report covering its reviews of all distributor methodologies and available at: <http://www.ea.govt.nz/dmsdocument/16276>. As of January 2016 the Authority had not formally responded to Castalia’s report.

- it recommends “Better integrating asset management (AMP) processes and pricing”. Our LRAIC approach currently integrates the two processes by signalling the economic cost of new investment in an average sense. In our view it is not practical in the vast majority of cases to try and link asset management and investment activity (which is inherently lumpy and localised) with pricing. Any attempt to do so would likely lead to price volatility over time, and very different price signals in different parts of the network. We consider that such price signals serve no useful economic purpose as they are likely to confuse most customers.²² Such signals would also likely be poorly received by retailers who could reasonably argue that they are not consistent with principles (d) and (e).
- it states that “It is common for distributors to set prices for industrial and commercial customers close to incremental cost...”²³ and price higher to other, for example residential, customers. We cannot speak for other distributors, but Orion does not do this. Castalia does not state the basis for its conclusion that this is “common”.

In terms of its report on Orion’s methodology:

- Castalia says that our peak demand pricing is not linked to local network constraints, and that we do not present information on “service capacity at different areas of the network”²⁴. Our peak pricing is not trying to manage local constraints and so we have clarified our approach in the relevant sections of this methodology.
- Castalia correctly notes that we do not provide estimates of standalone cost.²⁵ We do not often see by-pass (there has been no case in the past ten years at least). To us this demonstrates that it is indeed uneconomic in most cases, but we are happy to consider any claim / threat on a case-by-case basis.²⁶
- for similar reasons we think it is not very useful for distributors to establish with any precision that prices are “subsidy-free” given the very wide range between incremental cost (usually around zero) and standalone cost, and in particular the observed non-incidence of by-pass.²⁷

²² We also note that the current transmission pricing methodology, while not without its critics, explicitly de-links the interconnection price (which is nationwide or ‘postage stamp’) from the individual investments that drive it, and that is with respect to only a few, relatively well informed and motivated Transpower customers.

²³ On page 28 of its summary report.

²⁴ Castalia review of Orion’s methodology, Table 2, p5.

²⁵ Ibid.

²⁶ We do observe that a number of larger customers use diesel generation as emergency back-up, but that none of these go the extra step and use diesel as an alternative to network connection. We take this as further indirect evidence that the all-in cost of network connection is lower than standalone cost, and given a marginal (fuel) cost of 30 to 40 cents per kWh this is understandable.

²⁷ And we note Castalia’s comment on p29 of its summary report that: “However, as discussed above (under principle a(i)), cross-subsidies will be very rare in a largely fixed cost business like electricity distribution.”

- Castalia states that “Orion does not provide any forecasts of investment needs.” and it is true that there are none in this methodology. There are forecasts in our asset management plan, and we think that is the appropriate place for them. As noted above, we do not agree with Castalia that it is useful or practical to try and closely link asset management planning with pricing in any detailed sense, and we think this idea needs further discussion. We consider that LRAIC signals the cost of investment in a generic sense, so that investment that is needed will occur when customers have indicated willingness to pay for it.

More generally, we note that information on pricing is contained in a number of documents, each targeted at different levels of knowledge, understanding and interest. We are considering how best to explain to customers that suite of information and where they can find what is relevant to their needs.

Separately, in 2012, the Authority consulted on a proposed “Economic and decision-making framework for distribution pricing methodology review”, and the Authority has since promulgated this framework. We are unsure how the Authority intends distributors to apply the framework, but since the principles and guidelines are held to be consistent with it, we see the principles and guidelines as being the relevant regulatory instrument.

In addition to the Authority’s approach, the Commission, in October 2012, promulgated its own information disclosure requirements related to pricing. These reference the Authority’s principles, but also include additional requirements of our methodology. There is some overlap in the two approaches.

The Authority is planning to review the pricing principles in mid 2017.

Electricity Authority pricing principles

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

Signal economic costs

- (a) *Prices are to signal the economic costs of service provision, by:*
- being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulation;*
 - having regard, to the extent practicable, to the level of available service capacity; and*
 - signalling, to the extent practicable, the impact of additional usage on future investment costs.*

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 and which, because it reflects the benefits that customers get from sharing in use of the network, is less than the standalone cost they would face. Conversely, at off-peak times (when the marginal cost of delivery is effectively zero) our marginal charge for delivery on the network is likewise very low. In these ways our pricing aligns with principle (a) i.

The LRAIC that we estimate is both a long-run and a network-wide value. This is not to suggest that the network is everywhere equally constrained or equally close to capacity limits in the

shorter term. Rather, it reflects our intention to provide a long-term price signal against which customers (or retailers or third parties) can invest in demand-side alternatives wherever they are on the network. By maintaining this incentive over the entire network and the long-term we help ensure that the demand response will be consistent and so can be assumed in our network design and planning. In this way we believe we align with principle (a) ii. But, for the avoidance of doubt, we *are not* trying to use prices to manage demand in the short term with respect to local constraints.

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. 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 willing to pay for it at a price higher than that of the alternatives (aligning with principle (a) iii).

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 to customers 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 do mean that the proportion of our charges that apply to energy volumes is probably higher than ideal, with the result that the savings that accrue to investment in technologies such as PV are probably overstated, and this may be leading to over-investment in PV to New Zealand's detriment. While this is not technically bypass (PV does not really support "standalone") the regulations also lead to customers with PV contributing materially less to our common costs than do otherwise equivalent customers.

Other costs

- (b) *Where prices on 'efficient' incremental costs would under-recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to consumers' demand responsiveness, to the extent practicable.*

The LRAIC-based component of our pricing does not recover allowed revenue. We set 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 very 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.

Tailored pricing

- (c) *Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to:*
- i. discourage uneconomic bypass;*
 - ii. allow for negotiation to better reflect the economic value of services and enable stakeholders to make price/quality trade-offs or non-standard arrangement for services; and*
 - iii. where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives (e.g. distributed generation or demand response) and technology innovation.*

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. This adjustment discourages uneconomic bypass - principle (c) i.

In some cases we individually negotiate the pricing and charge structure directly with the customer. This is because some large capacity connections can impact on the network to which they connect such that significant additional investment by Orion is required. Such cases also provide the opportunity to tailor the quality of the service to the specific needs of the customer. We usually devise individual pricing in such cases, in line with principle (c) ii. This is not a necessary approach for most connections and would be impractical for our smaller customers.

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.

Because our peak / control period prices signal the LRAIC of network investment, customers have a clear value against which to assess network alternatives. Many customers, particularly major customers, turn on generators, reduce demand or both in response to our pricing. Tens of thousands of residential customers heat their hot water only at night in response to the very low delivery cost which is generally preserved in retailers' rebundling of Orion's pricing.

More specifically, Orion offers export credits to encourage investment in generators that reliably generate during generation periods and also offers export credits for electricity exported onto our network to provide an economical alternative to electricity delivery during peak demand times. This aligns with principle (c) iii.

Overall though, when prices are cost-reflective, we do not need to be experts in demand side management solutions and technologies. Instead, our pricing inherently rewards any party that elects to invest and innovate in response, creating a basis for choice. We do not consider there is anything wrong with building more network if that is what customers efficiently choose. Rather, we seek to ensure new network is built when it is the best way of meeting customers' energy delivery needs as revealed by those customers' preferences and willingness to pay. Put another way, there is no *single set* of observable outcomes we would expect to see in terms of customer behaviour that would allow us to conclude that our pricing 'works' as well as it possibly can, and by definition there is no counterfactual in place that we can compare against. We do observe various forms and levels of customer response, and consider that it is reasonable to assert that these are consistent with our pricing.

Stability and transparency

(d) Development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact on stakeholders.

Orion openly discloses its pricing methodology and actively works to promote a stable and long term pricing basis, recognising in particular that customers make investments in response to our pricing:

- i. our structure for major customers has been in place for more than 20 years while our general connection pricing is essentially 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; and
- iv. longer-term price indications are provided to customers and retailers.

In addition to this methodology document we publish a plain English network pricing guide.²⁸ 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.

Complexity

(e) Development of prices should have regard to the impact of transaction costs on retailers, consumers and other stakeholders and should be economically equivalent across retailers.

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 that are reflected in our costs. Orion has relatively few connection categories (and 99% of connections are "general" connections) and there are relatively few prices within each category.

²⁸ Due to the earthquakes this document has not been updated since 2010. We intend to update it in the near future.

Pricing development is primarily focussed on achieving efficient outcomes for the long-term benefit of customers, but where possible we reduce retailer 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;
- simplified the structure of our loss factors so that there were only 4 where there were 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. (We also created specific loss factors for our two largest rural connections.)

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).

This year we:

- rebalanced the components of our major customer pricing.

Electricity Authority information disclosure guidelines

This section directs the reader to the relevant section of the body of our methodology document, and provides additional comment where appropriate.

(a) Prices should be based on a well-defined, clearly explained and published methodology, with any material revisions to the methodology notified and clearly marked.

This methodology document constitutes the first part of the above. Where material changes are made a marked-up version could be made available, although any such changes will have been signalled and consulted on well in advance.

(b) The pricing methodology should demonstrate:

(i) how the methodology links to the pricing principles and any non-compliance

See the assessment section above.

(ii) the rationale for the consumer groupings and the method for determining the allocation of consumers to the consumer groupings

See section 4.

(iii) quantification of key components of costs and revenues;

See sections 5 and 6.

(iv) an explanation of the cost allocation methodology and the rationale for the allocation to each consumer grouping;

See sections 4, 5 and 6 and Appendix D.

(v) an explanation of the derivation of the tariffs to be charged to each consumer group and the rationale for the tariff design; and

See section 7.

(vi) pricing arrangements that will be used to share the value of any deferral of investment in distribution and transmission assets, with the investors in alternatives such as distributed generation or load management, where alternatives are practicable and where network economics warrant.

See comments above under principle (a).

Also, we directly provide the opportunity for investors to provide alternatives to planned network reinforcement by publishing the planned projects and identifying the value of deferment in our asset management plan.

(c) The pricing methodology should:

(i) employ industry standard terminology, where possible; and

We consider that we use standard terminology, and in any case we seek to explain the technical terms that we use.

(ii) where a change to the previous pricing methodology is implemented, describe the impact on consumer classes and the transition arrangements implemented to introduce the new methodology.

Where changes are contemplated we consult with affected parties over a period of time. Our consultation material provides information on the impact on customers and we evaluate transitional arrangements as part of the process. We consider that our methodology document appropriately captures the result of our consulted changes. We avoid the added complexity of repeating the description of previous provisions and transitional arrangements within our published methodology.

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 sections 1 to 3.
2.4.1 (2)	See section 7.7.
2.4.1 (3)	See sections 4.5 and 7.6 for non-standard contracts. See section 8 for distributed generation.
2.4.1 (4)	See section 2.7.
2.4.2	The methodology has not (materially) changed.
2.4.3 (1)	See sections 4, 5 and 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 7.7.
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 section 3.2 and Appendix C.
2.4.5 (1) (a) to (c)	See section 4.5 and 7.6.
2.4.5 (2) (a) & (b)	See section 4.5.
2.4.5 (3) (a) & (b)	See section 8 and the price schedules.

Appendix C - Possible future pricing changes

This appendix expands on the discussion in sections 2.8, 3.2 and appendix B above and sets out Orion's current plans with respect to possible future pricing changes. This is primarily in response to the expectations set by the Authority that distributors should set out their plans for any such changes at six-monthly intervals. We believe this methodology document is the best place for annual updates of these plans to be set out. We separately provide updates between the annual updates.

The Authority's expectations were explained and set out in November 2016 as follows:²⁹

We will continue to facilitate the industry-led approach and intend to:

- *Monitor and report on distributor progress towards adopting efficient distribution price structures.*
- *Review the current distribution pricing principles and associated information disclosure guidelines and consult on any proposed changes.*
- *Assess alignment of distributor prices against the distribution pricing principles (each year from April 2018).*

We expect industry participants to continue to progress their work. Specifically, our expectations are that:

- *The ENA will continue to lead the development of more efficient pricing. We note the ENA will shortly release its New Pricing Options for Electricity Distributors consultation paper.*
- *Before 1 April 2017, each distributor will have published its plan for introducing efficient pricing. The purpose of setting a timeframe is to encourage distributors to communicate their intentions and to make progress. Information that we would expect to see in these plans includes:*
 - *a clear outline of the process each distributor will adopt, including the nature of their planned consultation with retailers and consumers*
 - *a timeline with the key milestones*
 - *resourcing implications, including how resources will be allocated to the process of moving towards efficient pricing structures.*

Submissions on the ENA (Electricity Networks Association) paper³⁰ referred to closed in December 2016. The ENA then issued a final guidance document focussing on five approaches.

The ENA document was a key input to our own consultation in August 2017. The various consultation documents are available on our website.

²⁹ See: <http://www.ea.govt.nz/development/work-programme/evolving-tech-business/distribution-pricing-review/development/next-steps-in-distribution-pricing-review/>.

³⁰ Available at: <http://ena.org.nz/wp-content/uploads/2016/11/New-Pricing-Options-technical-discussion-paper.pdf>.

Process

In terms of process, normally our annual pricing changes are relatively routine, and we would normally consult primarily with retailers. We consider that retailers remain the key stakeholders. However, the sorts of changes contemplated by the Authority, and some of the options considered by the ENA paper, potentially represent a fundamental shift in approach, with potentially significant impacts across the customer base. For that reason we believe we must undertake consumer consultation.

We have now completed some preliminary consultation primarily focused on the re-distributional consequences of volume-based charges when supply costs are largely fixed.

We anticipate further rounds of stakeholder consultation.³¹

Timeline

Because the size of the task is not yet known, we do not yet have a detailed timeline and milestones. However, we believe the following are key considerations:

- Changes to regulation under Part 4 of the Commerce Act that will apply to the next DPP reset – that is, from 1 April 2020. Of particular relevance is change in the form of control from a weighted average price cap to a revenue cap.
- The final form of the TPM guidelines issued by the Authority, and how this manifests in the actual TPM developed by Transpower. We doubt the latter will be effective before April 2020, and it could be a year or two (from now) before the form and implications of the new TPM are sufficiently well developed for their impact on our own pricing development to be clear.
- The Authority's review of the distribution pricing principles, currently scheduled for the second quarter of 2018.
- The Authority's recent changes to Part 6 of the Code (relating to the avoided cost of transmission) which, in Orion's case, come into effect from 1 October 2019.
- The extent of necessary consultation could be considerable.
- The knowledge that many other distributors will be making pricing changes at the same time. We need to keep abreast of these wider developments.

Resourcing

There are two key resourcing considerations:

- The relatively narrow consideration of how the pricing consultation and development is resourced. At this stage we expect this to be largely internal, although there may be some use of third parties for consumer consultation, and for external peer review. We also note that the ENA is leading and coordinating pricing reform activity across its membership. Availability of internal resources will be influenced by other Authority workstreams, for example its decisions on a default distributor agreement.
- The wider consideration of how broader business impacts are accommodated. Some possible pricing developments would likely require the development of new business

³¹ In any consultation we will use the Authority's consultation guidance as a key reference:
<http://www.ea.govt.nz/dmsdocument/13342>

processes and systems, with attendant time and costs. The materiality of such costs could raise the issue of how they can be recovered under Part 4.

Taken together, all of these considerations suggest that we are unlikely to implement material changes to our pricing before April 2020, although we may decide on what the changes are somewhat earlier than that. Depending on the magnitude of the changes, they may be phased in over a number of years.

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 much consumption (kWh) based. As a consequence, customers may be over-investing in technologies that reduce consumption, such as solar photo-voltaic panels. This is because they see value in reducing consumption when the retail price is, say, 25 cents per kilowatt-hour while the actual economic saving is typically less than 10 cents per kilowatt-hour.

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.³²

The Authority's recent guidance on how it will assess compliance with the regulations is a significant and helpful development here. We continue to work with the Authority, via the ENA, through the detail of this guidance. So far we are not convinced that it is permissive as the Authority appears to believe. However, our analysis so far shows that certain types of capacity charge that may be deemed to be variable by the Authority, have very similar customer impacts as higher fixed charges would. It may also be that customers see capacity charges as essentially fixed no matter how the regulations are interpreted.

We remain concerned that implementing changes that the Authority deems to be compliant will, in response to public pressure, lead to the regulations being changed so that such pricing changes become non-compliant with the changes then needing to be reversed. We would therefore look to MBIE to confirm that the Authority's guidance is consistent with the intent and purpose of the LFC regulations before making such changes. Even better would be for MBIE to do a thorough review of the regulations to see if they are still fit for purpose in a fast changing world. We are encouraged by developments here in terms of political party positions on the regulations, however, we will need to see concrete actions before we can confirm our direction.

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 (at 7 to 8kW) 3 to 4 times greater than their

³² This discussion focusses on our 'general' connections category which encompasses all residential customers as well as most small and medium sized businesses.

average coincident maximum demand (CMD) of 2 to 3kW.³³ This high diversity factor allows transmission and distribution networks to be built largely based on CMD, while still being able to support much higher AMDs close to connections. In fact, higher AMDs can support lower CMDs as well by enabling greater use of energy off-peak. This already happens with customers on “day/night” pricing.

- It may lead customers to believe they have a ‘right’ to whatever the nominated capacity is, when the upstream networks, which are, efficiently, built to support CMD, cannot handle this. 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. (The analogy is also poor as telecommunications providers are not required to offer a continuous set of offers of connection speeds. The Authority’s LFC guidance implies that distributors are.)

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, retailers³⁴ 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. We will thus be particularly interested in the Authority’s review of the pricing principles as they address the trade-off between efficiency and simplicity. We note Castalia in its 2013 report specifically identified that the principles do require consideration of trade-offs in their application, but that, as currently written, the principles provide little guidance in this area.

Our own (2017) consultation and feedback on it has re-confirmed retailer concerns about the complexity of our current approach to peak pricing. Because we believe that that most forms of so-called TOU pricing are inconsistent with our approach to load management, we have proposed progressing analysis of two alternative pricing approaches:

- one that provides for explicit rebates or credits where customers choose to allow us to manage elements of their load, and
- dynamically signalled but volume-based peak pricing, perhaps with a ‘reward’ price that would give back credits when the dynamically signalled duration exceeds some level.

The Authority’s TPM work is also relevant. While, under the latest 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 guidelines. The guidelines state that: “A capacity charge that varies

³³ 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.

³⁴ Not all retailers have the same views, but we consider it is accurate to say this is the predominant view among retailers, both the large and established and the new entrants.

according to the amount of electricity a consumer expects to consume is a variable charge.”³⁵
By contrast, the proposed TPM guidelines state:

*...to the extent that it can be economically achieved, [the TPM should] be designed such that a customer's residual charge will not change as a result of the customer's actions or the actions of another party other than Transpower, such that it does not create incentives or opportunities for designated transmission customers to inefficiently avoid the residual charge.*³⁶

Oakley Greenwood, for the Authority, put it another way in its further comments on the TPM cost benefit analysis:

*For such reduction or loss in allocative efficiency to occur implies that distribution businesses would structure their tariffs so that their now fixed transmission costs are recovered from customers via a variable charge. Our view is that pricing in this way would be inconsistent with economic theory. This also may make little commercial sense, if it exposes that business to volumetric risk (because its marginal prices differ to its marginal costs). In short, the outcome “conceived” is not a direct function of the wealth transfer per se, but rather a function of the (inefficient) tariff structures that are assumed to be adopted by the distribution business in response to that wealth transfer.*³⁷

In other words, the cost-benefit case for the TPM changes depends, in part, on distributors being able to price in a way that regulation prohibits, at least for most residential customers.

In summary then, we see that consistency of regulatory messages and approaches is essential if distributors are to move pricing in the expected direction and for the long term benefit of consumers.

³⁵ See “Variable charges under the low fixed charge Regulations: Guidelines”, at <http://www.ea.govt.nz/dmsdocument/21123>, para 2.18, p7.

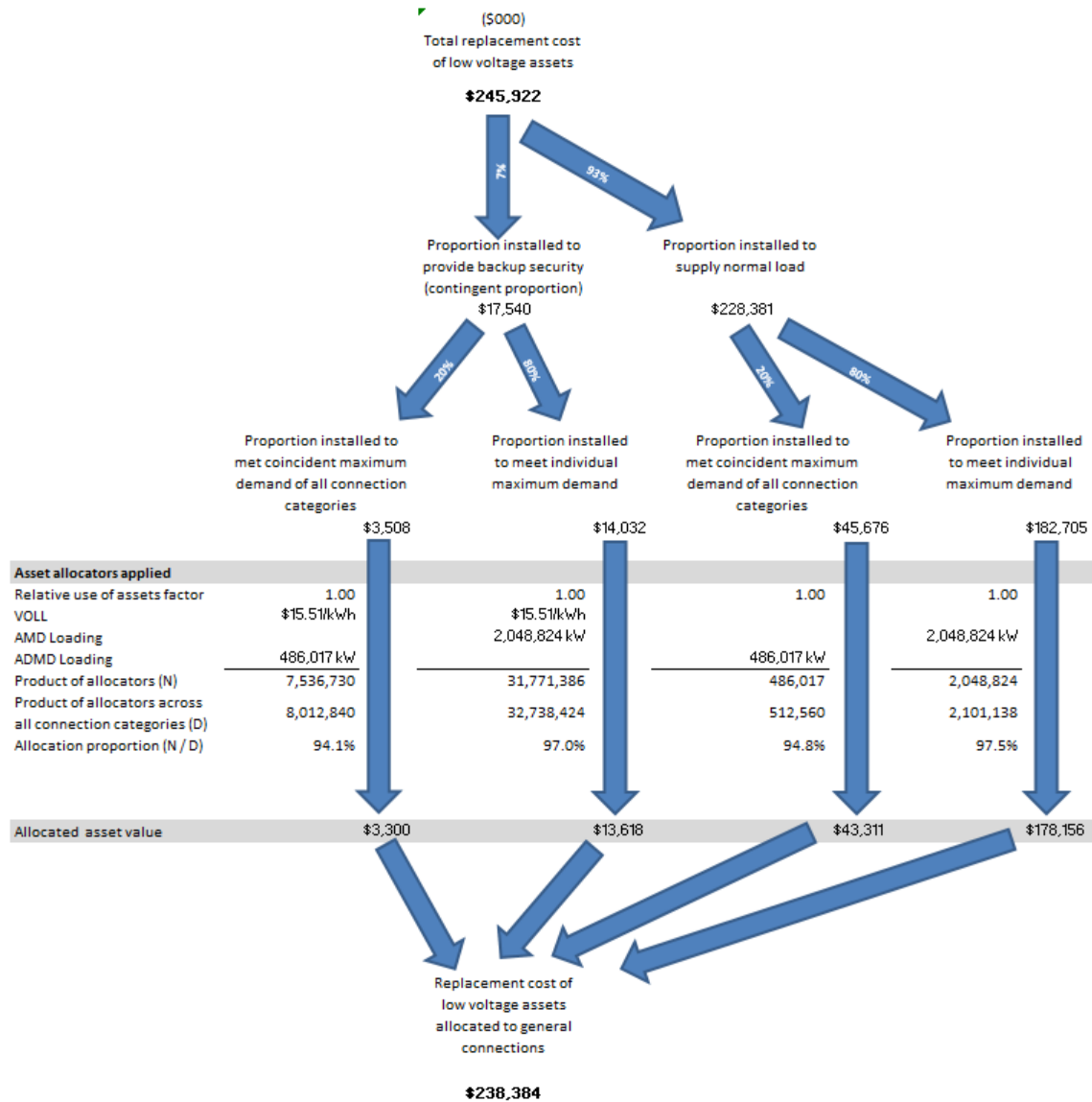
³⁶ See Appendix E – Proposed guidelines - to the latest TPM consultation paper, clause 32 (d).

³⁷ See Appendix B – Responses to issues raised on CBA - to the latest TPM consultation paper, p 37.

Appendix D - Asset allocation example

Asset allocation for low voltage assets to general connections

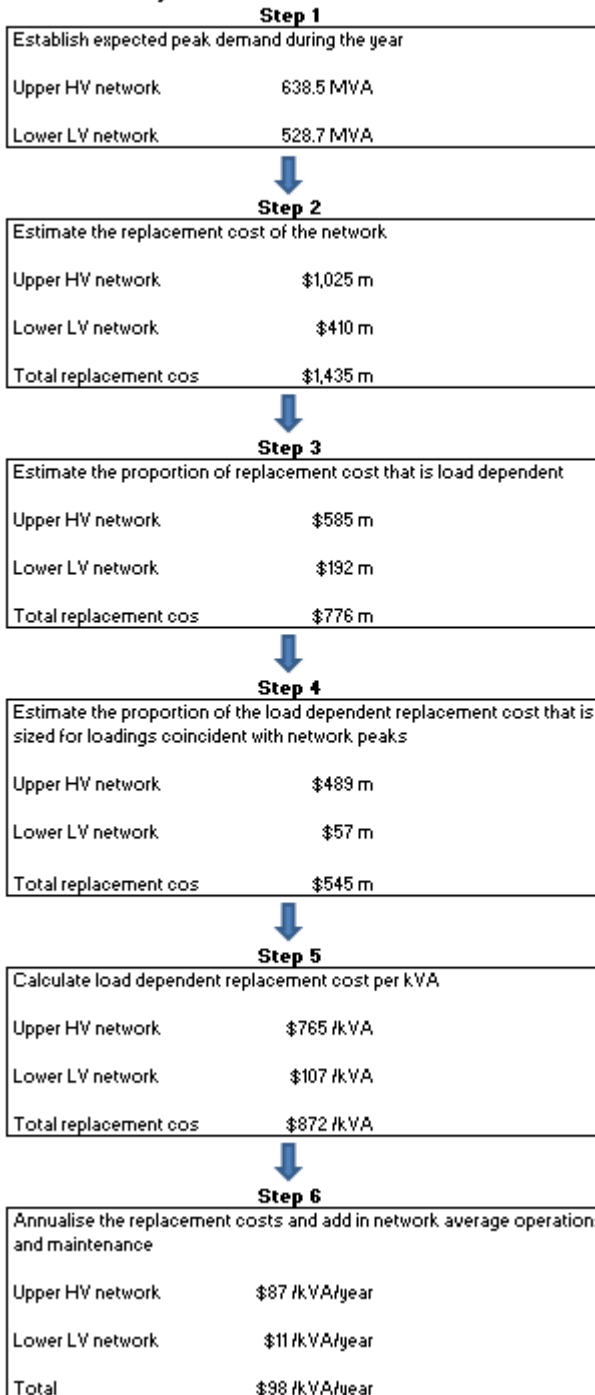
(based on replacement cost established in last regulatory ODV valuation)



Appendix E - Derivation of LRAIC

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

Derivation steps



See notes for each step on next page.

Notes

Step 1

This is the combined coincident peak demand of all loads

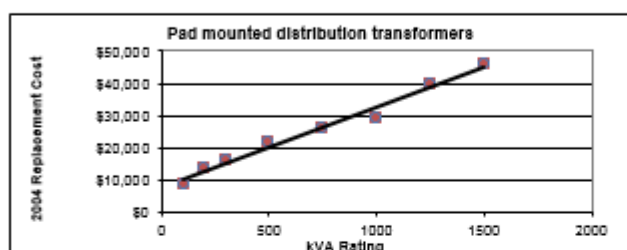
Step 2

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 quantities 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 levelised regulatory return, depreciation, taxation (including an allowance for the expected depreciation 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 variability) 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.

To be inserted after certification